BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matter of:	)
	) Docket No. 09-IEP-1O
Preparation of the 2009	)
Integrated Energy Policy Report	)
(2009 IEPR)	)

COMMITTEE WORKSHOP ON THE POTENTIAL NEED
FOR EMISSION REDUCTION CREDITS IN THE
SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

CALIFORNIA ENERGY COMMISSION
FIRST FLOOR, HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

MONDAY, SEPTEMBER 24, 2009

10:00 A.M.

Reported by:
Peter Petty
Contract Number:

COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member, IEPR Committee

James D. Boyd, Vice Chair and Associate Member, IEPR Committee; Presiding Member Transportation and Fuels Committee

Kelly Birkinshaw, His Advisor

STAFF PRESENT

Suzanne Korosec, IEPR Lead
David Vidaver
Michael Jaske
Matthew Layton

Also Present
Presenters

Mark Minick, Southern California Edison (SCE)
Catalin Micsa, California ISO (CAISO)
Kenneth Silver, (LADWP)
Bruce Moore, LADWP
Mohsen Nazemi, South Coast Air Quality Management District (SCAQMD)
Barbara Baird, SCAQMD
Oscar Abarca, SCACMD
Richard McCann, Aspen Environmental Group
Cory Welch, Summit Blue
Larry Kostrzewa, Edison Mission Energy
Michael Carroll, Latham and Watkins
Steve Sciortino, City of Anaheim

Panelists (Not Already Listed)

Keith Johnson, CAISO

Public Comment (Via WebEx)

Bruce Rising (PHON)
Mark Turner, Competitive Power Ventures
Shana Lazarow, Communities for a Better Environment
Don Vawter, AES Southland
Samantha Unger, Evolution Markets
Adrian Martinez, Natural Resources Defense Council (NRDC)
Jesse Marquez, Coalition for a Safe Environment
Gary Rubenstein, Sierra Research
Jeff Valmus, EmeraChem Power

INDEX

	Page
Introduction	
Suzanne Korosec, IEPR Lead	6
Opening Comments	
Commissioner Jeff Byron, Presiding Member of IEPR Committee	9
Vice Chair Jim Boyd, Associate Member of IEPR Committee and Presiding Member of Transportation Committee	9
Presentations	
Potential Dispatchable Capacity Needs in Southern California and the Los Angeles Basin	
Dave Vidaver, Electricity Analysis Office, California Energy Commission	13
Mark Minick, Southern California Edison	31
Catalin Micsa, California ISO	49, 130
Kenneth Silver, Los Angeles Department of Water and Power	72
Assessing Los Angeles Basin Reliability Given Environmental Constraints	
Richard McCann, Aspen Environmental Group	94
Cory Welch, Summit Blue	106
Market Conditions and Offset Availability in the South Coast Air Quality Management District	
Mohsen Nazemi, South Coast Air Quality Management District	90, 135

I N D E X

Page

Presentations

Developer Observations on ERC Procurement and Requirements

Larry Kostrzewa, Edison Mission Energy 157

Michael Carroll, Latham and Watkins 173

Steve Sciortino, City of Anaheim 197

Panel Discussion on ERC Procurement and Requirements 209

Moderators:

Mike Jaske, Matthew Layton, Dave Vidaver, CEC

Panelists:

Michael Carroll, Latham and Watkins

Keith Johnson, California ISO

Larry Kostrzewa, Edison Mission Energy

Mark Minick, Southern California Edison

Bruce Moore, Los Angeles Department of Water and Power

Mohsen Nazemi, South Coast Air Quality Management District

Steve Sciortino, City of Anaheim

Public Comments

Bruce Rising (phonetic)
30, 48, 90
Mark Turner, Competitive Power Ventures 70, 133
Barbara Baird, District Counsel for SCAQMD 91, 152
Shana Lazarow, Communities for a Better Environment 92
Don Vawter, AES Southland 129
Samantha Unger, Evolution Markets 130
Oscar Abarca, SCACMD 149

I N D E X

Page

Public Comments (Continued)

Jesse Marquez, Coalition for a Safe Environment 251
Adrian Martinez, Natural Resources Defense Council 260
Gary Rubenstein, Sierra Research 266
Jeff Valmus, EmeraChem Power 269

Adjournment 272

Certificate of Reporter 273

P R O C E E D I N G S

SEPTEMBER 24, 2009 10:05 a.m.

MS. KOROSEC: We are going to go ahead and get started now. Good morning, everyone. I am Suzanne Korosec. I lead the unit that produces the Energy Commission's Integrated Energy Policy Report, or IEPR. Welcome to today's IEPR Committee Workshop on the Potential Need for Emission Reduction Credits in the South Coast Air Quality Management District, given state policy goals to reduce the use of once-through cooling power plants and to retire or re-power the state's fleet of aging power plants.

Just a few housekeeping items before we get started. Restrooms are in the atrium, out the double doors and to your left, we have a snack room on the second floor at the top of the stairs, under the white awning, and if we have an emergency and we need to evacuate the building, please follow the staff out the door to the park that is diagonal to the building and wait for the all clear signal.

Today's workshop is being broadcast through our WebEx conferencing system. Parties need to be aware that we are recording the workshop. We will make that recording available on our website within a couple of days of the workshop, and we will also be providing a written transcript approximately two weeks after the date of the workshop.

For those of you who are listening in on WebEx, if you have questions during the day, please send them to the WebEx Coordinator and we will make pass those on to presenters. And during the public comment period at the end of the day today, we will hear first from people who are here in the room, and then we will open up the lines for the WebEx participants. For those of you in the room who want to make comments, we do ask you to come up to the center microphone at the podium so we can make sure that we capture your comments in the transcript. And it is also very helpful if you could give our Court Reporter your business card so we make sure we get your name and affiliation spelled correctly.

Moving on to our subject for today, the Scoping Order for the 2009 IEPR identified the need to evaluate the impacts of potential air pollution limits on new power generation in the South Coast Air Quality Management District, and the effect of those limits on efforts to replace aging power plants. I do need to emphasize that, while we are conducting this workshop as part of the 2009 IEPR, because of the complexity of this issue and all of the various efforts that are underway that will affect the outcome, this is simply one point on a longer timeline and a much longer process. For the 2009 IEPR, we will include the latest information that we have at the time the IEPR is published, but parties should not expect that this IEPR is going to recommend specific solutions to this issue.

In February of this year, the Energy Commission staff released a staff draft paper entitled "Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System." I have included the link to that here for parties who would like to review that paper. Today's comments and discussions, along with the written comments will be used to update that staff paper, and the resulting updated staff report will be circulated for public comment probably in December with a final report out in January 2010.

Just to note, we are accepting written comments on today's workshop until 5:00 p.m. on October 6th. Copies of today's agenda are on the table out in the foyer, but, just briefly, we will start with presentations this morning from the Energy Commission staff, followed by Southern California Edison, the California Independent System Operator, the Los

Angeles Department of Water and Power on potential dispatchable capacity needs in Southern California and in Los Angeles Basin. After that, we will be breaking for lunch, we will resume in the afternoon with a presentation on a consultant assessment of Los Angeles Basin Reliability, and then we will hear from South Coast Air Quality Management District on PM-10 Market Conditions and Offset Availability in the South Coast District. Next, we will have presentations from Edison Mission Energy, Latham and Watkins, and the City of Anaheim to provide the developer perspective; and finally, we will have a panel discussion on Emission Reduction Credit Procurement and Requirements, followed by an opportunity for public comments. Then, we will finish up the day with concluding remarks from the staff. So with that, Commissioner Byron, I will turn it over to you for opening remarks.

COMMISSIONER BYRON: Thank you. Welcome, everyone. I am Jeff Byron and I chair the Integrated Energy Policy Report Committee along with the Electricity and Natural Gas Committee here at the Commission. And with me is the Vice Chair, Commissioner Boyd, who is the Associate Member with me on both of those committees. So you might say we have two of the right five Commissioners here in the room. Also, to his left is his Advisor, Kelly Birkinshaw. This is a big topic. Commissioner, do you have anything you want to say before we start?

VICE CHAIR BOYD: Very little. But I did not realize until you said it that we are a dynasty. Anyway, welcome everybody to this workshop. Appreciate all of you being here and I am glad to see a reasonably sizeable audience on this subject because it is more than a sizeable subject matter. To me, it is not a stand alone issue, it is an issue that is -- if there is such a word -- co-joined, linked to, or whatever, a whole lot of other issues that we are wrestling with at the present time, be it the once-through cooling, our old policy retiring old and inefficient plants, or the consequences and ramifications of the California Climate Change Program and activities. So, as we come together in an Integrated Energy Policy Report, we have got to look at it in that context, but today is to really talk about this specific problem. And there could be hosts of solutions to these multiple problems, not just repower, replace, but there is transmission and/or distribution system and/or more DG, CCHP/ activities or Job 1 in California is, you know, squeeze all the efficiency we can out of things, even your television sets, but that is a different subject for a different day, and welcome any and all support you want to bring to that subject when we do get to it. In any event, I look forward, therefore, to the comments of any and all folks out there who are going to deal with this subject because this is part of an incredibly rapidly changing dynamic here in California, so we can keep up with it. Enough said.

COMMISIONER BYRON: Well, I will add my brief remarks, as well. Thank you for being here. This is a big issue. It has got all the makings of a blockbuster movie, I guess. It has got lawsuits, it has got -- I read an account last night of how the Legislature moved through the Assembly and the Senate last -- what -- two weeks ago on the 11th and the early morning of the 12th, and that was not a pretty picture. Of course, this issue is bigger than just power plants, it is unresolved -- maybe one day we are all going to see books written about it. But in the mean time, we need solutions. We need solutions that address the health, environmental concerns, the economic impact, and an interest of this Commission -- and we believe on behalf of the rest of California -- is the retirement of aging, less efficient, and polluting power plants, of which there are up to 8,000 Megawatts that may be retired over the next 10 years.

Also, in June of this year, as Commissioner Boyd indicated, there was another issue that is closely tied to this, the State Water Resource Control Board issued a draft policy on the use of ocean water for power plant cooling. And that means generation units on the coast that are using OTC will have to either re-fit their cooling, repower, or retire. And that means a great deal of money and investments will have to be made, but we will also need to make a lot of investments in energy efficiency, and demand response, and renewables, and transmission upgrades, and that will be helpful because, within the LA Basin, that will help, but not completely mitigate this problem. Many of the OTC plants will likely retire, but many will still be needed. Retrofitting may be infeasible, or uneconomic, and it is going to require either repowering those units, or retirement or replacement. Retirement or replacement is going to require Air Emission Credits and ARC's, the Air Reduction Credits for primarily PM-10, are not available due to market constraints and litigation.

So today, we want to hear from a diverse and knowledgeable group of folks, we want to understand these issues, and we want to discuss potential solutions. I am looking forward to a very constructive and open dialogue from all of you, this is not a court of law, everyone's interest is joined here in one way or another, and we are missing some key folks. Unfortunately, we got a late request from some of the plaintiffs in the litigation to move the date for this workshop because they were unable to attend. I apologize, we were not able to move it. We have some obligations to get our Integrated Energy Policy Report done. We will be making recommendations following your input, what we hear today, and your written comments. And I really hope that we will receive good constructive input from those parties that were not able to be here today.

With that, I would like to thank you all very much. I am very keen to hear what you all have to say. I am going to go ahead and turn it over to staff at this point, and ask them if we can do our best to get through a lot of information on probably an optimistic schedule, but we will stay until we get it. Mr. Vidaver.

MR. VIDAVER: Thank you, Commissioner. Good morning. It has been a while since I have used one of these, there we go. First of all, I want to apologize to Commissioner Byron, he has declared this hearing room an acronym-free zone, and the title of my presentation is four acronyms in the first 10 words, so just to save space. We have a full day, so I will not dwell on the seriousness of the issue under discussion.

The IEPR record is replete with statements regarding the need to replace some share of these existing capacity in the area under District SCAQMD jurisdiction, so as to both comply with the Water Board policy and once-through cooling, maintain reliable electric service in Southern California, and the L.A. Basin, and facilitate the insertion of intermittent renewables on the scale needed to meet the State's ambitious renewable energy targets. I think most parties in this room would agree that legislative solutions that solve this problem one facility at a time are perhaps not as desirable as a more structured approach that would address the long-term needs for capacity in the Basin.

We have effectively divided the workshop, as Suzanne intimated, into two halves, the first dealing with the need for new dispatchable gas-fired capacity in the LA Basin over the next decade and the planning studies needed to isolate that range of values; the second half will deal with associated Emission Reduction Credits and offsets needed by that capacity and where they might come from.

COMMISSIONER BYRON: Mr. Vidaver, if you do not mind, I apologize, Ms. Korosec just informed me that I am uninformed, despite the request that we received to delay the workshop, I understand that a number of the parties communicated they could not be present today are indeed here, and I am glad to hear that, we welcome your input. Please go right ahead.

MR. VIDAVER: The inability to permit new power plants in the area under District jurisdiction is largely a problem of being unable to do so within two transmission constrained areas, the California ISO defined Los Angeles Basin Local Reliability Area and the Los Angeles Basin portion of the Los Angeles Department of Water and Power Control Area. Meeting NERC guidelines for maintaining reliable service under extreme peak load conditions requires threshold amounts of capacity within these areas. The need for Emission Reduction Credits and offsets is likely to be greatest within the two areas as the generation units totaling more than 7,500 Megawatts at seven facilities that utilize once-through cooling in the area under SCAQMD jurisdiction all lie in these areas.

Now, conceptually, the problems facing planners is not a difficult one to characterize -- how much capacity do you need, and where, to meet LA Basin and sub-area capacity requirements? What does that capacity have to be able to do, dispatch-wise? And how much will existing capacity be able to contribute to those requirements? Once you have answered these questions, you have what you need in Los Angeles and need only to build enough capacity elsewhere in Southern California to meet area-wide requirements and share in that it provides the inertia needed by the system and the ramping capability needed to incorporate intermittent renewables.

There are a few uncertainties that make that difficult. Until a full set of compliance plans are submitted to the Water Board, approved and in place, it is not certain how much capacity of existing locations will be able to continue to operate. While it is anticipated that most once-through cooled units will require replacement, and thus emission reduction credits, it is possible that some units at existing locations will be allowed to continue to operate without modification, depending on Water Board treatment of compliance plans.

Transmission upgrades are expected to allow more energy to be imported into the Los Angeles Basin, reducing local capacity requirements, and the need for replacement and new capacity within the Basin. Renewable additions will affect the need for capacity both within and outside the LA Basin. Different portfolios of renewable resources will provide different amounts of capacity on inertia, and result in different amounts of ramping capability being required in the rest of the system.

Finally, targets for energy efficiency, approximate set of demand response, and interruptible load programs, however well estimated, may ultimately prove to be unreachable within the time periods desired. And even if one can forecast accurately the need for capacity in the LA Basin, the Emission Reduction Credits and offsets needed by this capacity, and the sources from which they might come are uncertain. This you have all seen.

The need for Emission Reduction Credits in the District over the next decade will be driven to a great extent by the state of Water Board policy on once-through cooling. As I mentioned, the draft policy will likely require the replacement of existing turbines and, thus, Emission Reduction Credits or offsets if they are to continue to operate. Key questions are, thus, how much of this capacity will need to be replaced with gas-fired capacity, located on-site or elsewhere in the LA Basin, and how much, if any, will be allowed to continue to operate under, for example, wholly disproportionate clauses in the final loaded word policy.

And, we have to solve all of these problems rather quickly. Compliance plans due, I believe, six months after the approval of the policy must include a discussion of how the facility plans to comply and provide some indication as to when, by showing that the refitting or repowering is being coordinated with the ISO, or LADWP, it has generally exceeded the compliance, or will require repowering or replacement in most cases. Some modifications, both physical plant and operation, are necessary within one year of the approval of the Water Board policy. Unless operators can demonstrate that reduced flows are necessary for operations or maintenance, those will have to be reduced.

It is anticipated that the cost of plant modifications must be picked up by counterparty Star (PHONETIC) contracts. Five years after approval of the policy, mitigation will be required of those plants that have yet to comply. Owners can demonstrate that they are doing so for existing efforts, can fund an ongoing mitigation project, or develop or implement a new project. In any case, as we expect parties to undertake major investments, only with a guarantee of cost recovery in the form of a long-term contract, the dates that these contracts are offered to facilities are very important. If the Public Utilities Commission is to authorize the procurement of new and replacement capacity needed in the LA Basin in the form of approval of Southern California Edison's 2012 Procurement Plan at the end of 2012, the ISO's 2012 Transmission planning process will have to evaluate transmission alternatives that might affect the need for capacity in the LA Basin. Failure to adequately consider in-basin needs for new capacity, as part of the 2012 CPUC Procurement Cycle, runs the risk of later procurement that restricts the options available to meet local reliability needs, ignores transmission solutions, requires gas-fired capacity that might otherwise not be necessary, and precludes competitive solicitations, thus raising ratepayer costs.

Here are all the power plants involved. We have seven gas-fired facilities under SCAQMD jurisdiction that utilize FTC; we have four projects that are going forward in South's estimation, Inland Empire 2 should be online before next summer, Cambian (phonetic) should be permitted and available to the City of Anaheim, the Riverside Expansion 96

Megawatts should begin construction shortly, and staff anticipates that the expansion of the Watson Co-Generation facility will take place within the next two years. This is a total of 786 Megawatts. We also have three projects contracted for by Edison, Walnut Creek, Sentinal and El Segundo, and three other projects within the Basin who are currently stalled by the moratorium, the Southeast Regional Energy Project, also known as the Vernon Project, Sun Valley, and Hydro. There are also two out-of-area projects that rely on credits that are currently unavailable, Palmdale and Victorville 2. It is interesting that, with the exception of projects coming before the Commission within the San Diego Los Angeles Reliability Area, and Blythe 1 and 2, all the gas-fired projects coming before the Commission are either in SCAQMD jurisdiction, or are relying on credits -- Palmdale and Victorville 2. This is quite natural developers would assume that, in anticipation of needing to replace once-through cooled plants, being able to provide local reliability services, that most of the projects we see would be under SCAQMD jurisdiction and within the local reliability area. So we have a lot of eggs in one basket.

Here are the projects that I alluded to and their sizes, three still have contracts, four without, and two outside the Basin, but relying on credits that are stalled by the moratorium.

This is pretty ISO-centric. The Water Board policy affects the Los Angeles Department of Water and Power. They have planned replacements for two units at Haynes, and two units at Scattergood, which predate the Water Board policy. These repowerings or replacements are designed to integrate additional renewables into their system, maintain local reliability, and reduce gas-fired Megawatt hour and Btu per Megawatt hour in the process. There remains uncertainty, however, regarding both the need to modify remaining units under their ownership in order to comply with the Water Board policy, as well as where any necessary emission reduction credits might come from.

Okay, numbers. We have necessary capacity in two dimensions, both within the Los Angeles Basin and across Southern California as a whole. I want to deal with the latter first. You need sufficient capacity in both the LA Basin and across the entire area in South of Path 26. You will see that staff estimates of current and near term reserve margins in Southern California are on the order of 27-28 percent, or more than 3,000 Megawatts above the 15 percent generally exceeded as minimally necessary for reliability on its own basis. How did we get to this point? In approving 1,200 to 1,700 Megawatts of new capacity for Southern California in late 2007, the Public Utilities

Commission in the 2006 Procurement Cycle, estimated that SB 26 would be along roughly 1,100 Megawatts in 2010. Since then, the peak load forecast, here the revised 2009 IEPR load forecast is used, has dropped by 800 Megawatts, the Procurement Proceeding also assumed that more than 1,800 Megawatts of capacity in Southern California would be retired by 2010. Conventional wisdom at present is that half of South Bay will be retired. So the entire difference between the 1,100 Megawatts assumed by the CPUC roughly two years ago, and the 3,200 Megawatts we see today, can be explained by those two facts. So going forward to 2016, compared to 2010, the surplus estimated by staff is only slightly smaller, 2,900 Megawatts. 2,400 Megawatts in load growth has been almost entirely offset by 1,000 Megawatts of new thermal and a 1,700 Megawatt increase in renewable capacity. And we retired all the South Pad (phonetic) If we assume that El Segundo complies with the Water Board policy by retiring prior to the summer of 2015, the surplus drops to 2,250 Megawatts. These numbers are not surprising if one recalls that the authorization for what have become Walnut Creek, El Segundo, and Sentinel, is part of a fleet replacement policy, that assumes close to 7,000 Megawatts of retirements by 2016.

So what might be wrong with this picture? In many respects, these numbers are very conservative. The demand response and interruptible load numbers are more than 1,000 Megawatts below numbers submitted by Southern California Edison and San Diego Gas and Electric to the CPUC and the Energy Commission within the last year. Thermal additions are limited to exceptionally high probability projects. There are no entries for co-generation. One source of risk here through 2016 is the assumed renewable additions, some 1,150 Megawatts of the 1,743 assumed by 2016. Roughly 290 Megawatts in each of 2013 and 2016 is large scale solar that Edison and San Diego have already contracted with. This is a risk. Two days ago, the number on this chart was 300 Megawatts larger, then the Bright Source Project fell through. So the scale of renewables assumed here is significantly dependent upon the siting and construction of large scale solar.

We have almost 2,000 Megawatts of new thermal assumed here. This does not include Walnut Creek, El Segundo, or El Centro. It includes seven units, only two of which require approval at the Commission, Canyon and Watson Co-Gen, Inland Empire 2, if GE is lucky this time, we will be up before next summer. Riverside should be online by August, they are in pre-construction. Blythe requires the completion of a transmission upgrade. Otay Mesa and Orange Grove are both under construction. So the additions we assume are very conservative.

Now, turning to the LA Basin itself, supply is in excess of current LCR requirements. We estimate just under 12,000 Megawatts of generation capacity in the LA Local Reliability Area, that is about 300 Megawatts in the ISO, as in their LCR studies. All but about 1,200 of this provided some form of resource adequacy under contracting the summer of 2009. The 2010 LCR of 9,735 Megawatts taken from the 2010 LCR Study that the ISO did will rise with load growth and would be expected to follow the transmission upgrades. This tidy surplus assumes that there are no once-through cooling policy-induced retirements.

Looking at the supply demand balances that were in the Los Angeles Basin, the three bolded numbers on the top line were taken from ISF studies, the remaining numbers are simply the LCR grown at the rate of load growth, as assumed in the staff's revised 2009 IEPR forecast. The new thermal are the four plants within the LA Basin. On the list just shown, Inland Empire, Riverside, Canyon and Watson, the demand response and interruptible numbers are simply a flat 70 percent of SB 26, the numbers on the previous chart, you will see that the surpluses are rather substantial, but unless that number is reduced for yield, we are going to start talking about why it is not representative of what you can retire. And you could see what happens to those surpluses when we begin to implement the State Water Board's policy along a timeline hoped for, El Segundo retiring here prior to the summer of 2015, its compliance date is the end of 2015, and then the remaining capacity both in the Basin and elsewhere, Encino, Ormond Beach, and Mandalay retiring prior to the summer of 2020. Again, these are pretty conservative numbers. They do not include a series of potential supply side resources that you would consider in a planning context, and that the CPUC will no doubt consider in their upcoming 2010 Procurement Cycle. One could include higher levels of renewables. Here, the in-Basin numbers are primarily Southern California Edison's 500 Megawatt Solar Project, 1-2 Megawatt rooftop facilities, half under their ownership, half under contract, but have been approved by the CPUC. There are a number of things we have not assumed. We have not assumed the additional wind at the Palm Springs CREZ, which the CPUC Procurement Proceeding -- the 2008 Procurement Proceeding -- puts at a potential of about 700 Megawatts. We have not assumed the development of in-Basin solar photovoltaic at rural substations, a potential brought forth in the current CPUC proceeding. The study commissioned by the CPUC did not allocate that potential to in-Basin and out-of-Basin locations. The study itself noted that it was really a first cut; they needed to look at lot more closely at the constraints on developing these projects, so they were not included. And we have not included co-generation. The Energy Commission has commissioned a report which will be out within the next couple of weeks, which shows that the in-Basin, including LADWP, potential for co-generation absent any additional incentives is on the order of 600 Megawatts through 2019, and that if one adds such incentives as putting combustion technologies back into the soft generation incentive program, providing CO_2 reduction payments to co-generation, you could increase that number from 600 Megawatts through about 900, and if you offered incentives for export, you could get perhaps another 700 megawatts of large co-gen in the LA Basin, including LADWP. Those numbers have not been included here.

Now the three caveats. The surplus of capacity in-Basin only indicates that one of the constraints on the retirement and replacement of OTC capacity might be binding. There are three others. We have grid stability in Los Angeles Basin, which requires a commitment of units in specific sub-areas in the Basin under high load conditions, basically in Southern California demand increases during the day, more capacity has to be committed from a set of units in the LA Basin to meet two constraints, which I will get into in a minute. There needs to be enough generation online and unloaded upper blocks (phonetic) available to provide sufficient inertia that sustain imports, I will talk about that briefly, and I trust that people who follow me will talk about that, as well, and then the system must have sufficient ramping capability to absorb intermittent resources.

The sub-LA Basin capacity requirements require the commitment of increasing amounts of capacity as load increases in both Orange County and south of Lugo Substation. The dispatchable capacity cannot be retired in amounts and at locations that were threatened at being able to satisfy these constraints. Now, I would really like to talk in some great detail now about the Orange County constraint, but you can see I cannot. So I know what the numbers are under here, but if I started talking about them, the ISO would beat me to death with a lawyer.

COMMISSIONER BYRON: Well, you have others to contend with, Mr. Vidaver -- why cannot you talk about that?

MR. VIDAVER: The ISO actually has three criteria that documents must meet to be released to the public, and market sensitivity, system security, and proprietary are sort of three tests that it has to pass. Perhaps one of the lawyers that I would be beaten to death with could explain exactly why this falls under that, and to be honest, I am not entirely sure. So --

The need for inertia in a nutshell, people following me know far more about this than I do, there must be sufficient generation operating in California to provide inertia to sustain imports. The amount of inertia that is necessary is a function of Southern California loads. The load on major transmission lines into Southern California, the load on the eastern river, inter-tie, how many units are on the Palo Verde. The amount of inertia that a given power plant provides depends on the technology. Unfortunately for those of us who would like to replace once-through cooled facilities, the steam turbines provide exceptionally large amounts of inertia. So if you retire large amounts of steam turbines, you need to ensure that you have sufficient inertia being provided by replacement facilities. Solar photovoltaics do not provide inertia, solar thermal does. I believe advanced wind does, but some forms of wind do not. So I am sure this will be covered in far more detail. And, again, I would show you the ISO operating procedure that indicates how much generation is needed under various load conditions in Southern California, but that operating procedure looks a lot like the one I just showed you, so I cannot do that.

And the finally, the system needs enough ramping capability to handle the intermittent resources that large amounts of wind on the system will, in all likelihood, increase the peak-trough ratio, and the size of the evening and morning ramps, so you need dispatchable capacity under

ISO control, basically, to satisfy loads as they increase during the day, and fall during the evening. And the existing steam turbines, in that they are able to operate at very low load levels, are kind of a natural source of that ramping capacity. So I imagine the ISO will elaborate on that. So I think that is it for my presentation. There are people coming up after me who can probably answer many of the questions you have far better than I can, but I will give it a shot.

COMMISSIONER BYRON: I was just going to suggest, you know, you went through so much, so quickly, that you just go through it all again, a little slower.

MR. VIDAVER: I am seven minutes behind. So I apologize. Well, you really have got to get me out of here. Give me the hook.

COMMISSIONER BYRON: Yeah, but a couple of things merit some comment, I think. Commissioner, do you have any comments or questions for David?

VICE CHAIR BOYD: Well, I was going to take David's advice and see if I learned from others what I do not understand so far, but I am anxious to hear your questions.

COMMISSIONER BYRON: So let's do it that way, but there are some things that I think need to be clarified, and I hope others that follow will address some of these issues.

Let me state the obvious first. Clearly, the numbers that you have put up here, the tables of information, there is a great deal of information, a lot of assumptions involved in there. I have written down a number of comments as I went along. We will certainly look for folks to comment with regard to some of the assumptions that you have made. I have a question for you. You said Bright Source had a project fall through, 300 Megawatts. What is that? I had not heard that.

MR. VIDAVER: It is my understanding that Edison just withdrew the Advice Letter on the Bright Source Project.

COMMISSIONER BYRON: All right, that is fine. We will let that go. That was one I was not aware of. But clearly, the economic impact in the Southern California areas have a dramatic effect on the demand we are seeing, a little bit of a lag here, but this problem will not go away. And we do see, despite all our best efforts at energy efficiency and demand response programs, there is still growth in the area, and we are going to continue to seek growth and demand, but there is some lag and -- how can I say it? I guess there is a silver lining to a declining economy from an electricity point of view. There is a lot of information that is contained here. I look forward to future commenters and presenters addressing those issues that they feel that they can contribute to.

I am concerned about one thing, and that is the comments that you made with regard -- and I know that folks from the Independent System Operator are here today -- but comments that some of this information cannot be discussed or shown for security reasons, or market power or safety, or whatever, it is extremely important that there be as much transparency as possible here. We need to convince the public that we are trustworthy in the evaluation that we are doing, and just to hide behind these kinds of things as others in this industry do typically to protect their customers is not going to cut it; we really do have to think about getting this information out there and open and in the public if we are going to get resolution on any of these issues. So I am not going to hold you responsible for that yet. But I think, Mr. Vidaver, excellent presentation, and a lot of material here to digest, but I agree with you, let's continue. We have many good speakers to go, and if we do not get these answers, we will come back to you later.

MS. KOROSEC: Commissioner Byron, we do have one question from a WebEx participant if we --

COMMISSIONER BYRON: All right, if it is clarifying question, we will take it.

MS. KOROSEC: All right, could we open the line for Mr. Bruce Rising? Bruce, are you on the line?

MR. RISING: Yeah. I was just curious, though, when you classified renewables, when you had the peaking, you did a sum of the total supply of Megawatts. Can you really add the renewables to that capacity? Or has that been discounted to account for the intermittency?

MR. VIDAVER: Big haircut, yeah. It is seriously discounted.

COMMISSIONER BYRON: Yeah, these are peak demand numbers that you have got on the table. I mean, I would imagine that wind, in general, does not contribute to supply.

MR. RISING: Okay.

MR. VIDAVER: Yeah, I think we actually rated the solar projects at Edison as generating at about 60 percent of main play on peak.

MR. RISING: Okay.

COMMISSIONER BYRON: I think it is fair to say, the staff has not done the worst case kind of analysis here, they have tried to be fair in terms of what gets added and what gets subtracted, but you do have to consider that there is a lot of variables at play here, a lot of assumptions that may or may not bear out. All right, thank you for the question. So we will continue. Mr. Minick from Southern California Edison.

MR. MINICK: Good morning. Unfortunately, I do not think I am going to answer all your questions on how to solve this particular issue. And bear with me, I am a generation planner for 30 years at Edison, I am not a transmission planner, so I can conceptually talk about inertia, but you need some very very detailed physics people to talk about exactly how inertia works.

COMMISSIONER BYRON: Well, I can appreciate that, Mr. Minick, but you always give us good information in presentations and I am glad you are here today.

MR. MINICK: Thank you. And I have a clarifying question that Dave can answer later. On one of his charts, he showed 10,000 100-Megawatts of imports across the board in all the years, and I realize that is probably based on the availability of imports, but, again, that number is tied to inertia, and I think that could be significantly downgraded. If the inertia in the LA Basin changes, we cannot import that much, which would affect that table. And we will make our comments to you by the October 6th time point on those particular numbers.

So defining the need for LA Basin dispatchable resources is difficult, mainly because we do not know what the future is going to be in the way of resources, in general. So let's sort of march through it. The things that are out there right now, there is an ISO report, and the ISO can tell you many more details about this particular report. I reference it here because it does exist, they did a pretty good job, and we are trying to update this report with the ISO. If you did not know, Edison is working with the ISO to try to do an intermittent analysis of future intermittent resources, or higher levels of renewables by 2020 in the 33 percent range. We hope to have the preliminary estimates done this year. It is a very complex issue and very difficult to analyze, and we are trying to sort of stretch the use of production simulation models in this work right now, so we may have some information before you later.

What the ISO found in their preliminary study was, is that you kind of meet the needs of the system with 20 percent renewables, with the existing generation or equivalent amount. So that, in simple, says we think we can get by with 20 percent if you will leave the units alone, or, if you take one out, put one in that is about the same size. Inertia is a little bit different, but that is basically what they were saying. When we go to higher levels, we are probably going to need more dispatchable resources, certainly, because intermittents vary significantly. We are not sure about the effects on the system without making significant transmission upgrades, and we will talk about that later.

I think we submitted to you the results of a

Nexant study that we did with the other utilities about a year ago, or six months ago. Again, this was a preliminary analysis, it did show some revealing information about higher levels of renewables regarding surplus energy at certain times of the year. That was pretty good results. It was not that definitive about how many quick start ramping resources we needed. So, the number that I show in here, the 2250, is resultant on we think we can dispatch these resources enough to respond to intermittency. It did not look at local reliability problems for transmission issues. We did not have time in that study to do a detailed transmission grid assessment of can the grid meet all the NERC and WECC, and ISO requirements for keeping the grid stable and safe. So this simply says we think we need some quick start resources in the future. That is one reason why we need these new contracts that we have signed, that seem to be tied up in the PM-10 litigation.

The other numbers you see here at the very bottom of the page are simply extrapolations from the ISO Need Assessment. The first numbers in 2006 are what the ISO says they typically need. We took a look at what we thought we would need in 2025 of 33 percent renewables, based on an extrapolation of that data. The analysis we are doing right now should come back with a much more definitive answer because these ranges are pretty large right now, and we are working on that right now with the ISO.

COMMISSIONER BYRON: And, Mr. Minick, just so that everyone understands what "ramping" means, that is typically a unit that can be dispatched with known availability that can ramp up at a certain rate of Megawatts per hour. Correct?

MR. MINICK: Actually it is in a 10-minute period of time. People bid into the market their ability to ramp over a 10-minute period of time.

COMMISSIONER BYRON: And what kind of generation qualifies for that?

MR. MINICK: Any generation can qualify for that if they can prove to the ISO that they have that capability. So hypothetically, take our hydro plants. If they are running at minimal load, or off, they can typically ramp to maybe 60 percent of their full load output per minute, so they can get to full load in two or three minutes, so they have very good ramping capability. Take a fossil plant -- and we used to own most of the plants that are now owned by the markets, so I know something about those plants -- typically it is 1 or 2 percent, so if there is a 500 Megawatt project or steam unit, and they are sitting at half load, so they have some capability to ramp, it is how quickly can they ramp in a 10-minute period of time. So if it is 1 percent per minute, that is 5 Megawatts a minute, 10 minutes is 50 Megawatts, so that unit sitting at half load could bid 50 Megawatts into the ramp or ancillary service markets. That is how much you can provide. Now, a peaker, if it can start in 10 minutes, could probably bid its entire amount, so if it is a 100 Megawatt peaker, it can bid in to the ramping requirements and start, it can be up and running at full load in 10 minutes, then its full output could be considered ramping.

COMMISSIONER BYRON: And the peaker is the natural gas units?

MR. MINICK: And the peakers are natural gas units.

COMMISSIONER BYRON: Simple cycle natural gas.

MR. MINICK: Yeah, typically. Now, we can look at advance technologies in the future, compressed energy storage, can we extract it, pumped hydro, batteries, those are all capable of providing that service, but they are kind of new and we are still trying to experiment with how they might be modeled in our models right now.

COMMISSIONER BYRON: All right, thanks for the little diversion there, just to make sure everybody understands "ramping."

MR. MINICK: Now, again, we have talked about SCIT. SCIT is the Southern California Import Transmission nomogram, and without showing the chart, it simply says that, when you have different levels of inertia in the LA Basin, you can import different levels, the higher inertia, the more you can import. It is imports both from the Northwest and from the East from Arizona. And you have to balance the two, and there are limits to how much you can bring in. As Dave rightly said, old steam plants have significant amounts of inertia. One of my charts will say kind of what we are trading off here. The retirement of older plants and replaced with in-Basin distributed generation -- photovoltaics, even small co-gens or peakers -- most likely will reduce your inertia. We have not run the studies to say, "How much can I import in a future world with half or all of my OTC plant shut down?" We are going to be looking at that. Give us a little bit of time and we will maybe have an answer for you in six months.

Importing more renewables from outside the LA Basin basically is an import; so I just said importing from the Northwest and importing from Arizona, importing from the desert is an import, so you are going to want to increase imports and decrease inertia, the two do not go hand in hand. It is going to be an interesting, complex thing to try to solve. As far as local capacity requirements in the Basin, dispatchable capacity is needed to maintain certain loadings on certain lines. As you all know, voltage issues rise all over our transmission system based on how much you are trying to import, what our loads are, and what generation is there. So if we had some flexible generation that we can start in the Basin to prop up voltage in places, that works pretty well. That is sort of our traditional transmission and generation planning. To change that, we are going to have to put in new lines, larger capacities, static bar compensation, and/or batteries or some new way to do it. We have not even figured out how to do this yet, so you are sort of way ahead of us saying you want the answer; we will give you an answer, but it is going to take us probably a couple of years to figure it out, working with the ISO, basically, to do that also.

COMMISSIONER BYRON: Well, and your brief explanation there is really good because, I mean, Mr. Vidaver shows us a table, and everybody can add up numbers, and it looks real simple. You make some assumptions, you add in the Megawatts that you are going to add, the ones you are going to subtract and, hey, what is the problem? But it is a lot more complicated than that, and it is more difficult to understand. So even though you have only scratched the surface there, we can appreciate this, not just add the numbers up in the table.

MR. MINICK: Right, thank you. Well said. Now, as David showed, these are some assumed additions that he put in. However, notice the big bold red numbers -- letters beside the units with lower inertia potential -- these units and some of the notes on there say "near the Arizona border," inertia at the Arizona border has some value in the LA Basin, but very little. And once near the Mexico border, that does not really help the LA Basin a lot, and those are the two biggest units on there. So we are not getting the kind of inertia we need with these new replacement resources. The ones that are retiring are in the Basin, are large steam turbines, and provide significant amounts of inertia, so we are going to have to solve this particular issue.

Now, about the PM-10 credits issue, we have four contracts -- sometimes I say they are three units because Sentinel was two contracts, we signed some units under the first contract, we signed with them on some with the second, the entire plant is close to the 800 Megawatts nameplate rating, will probably be 750 actual rating. But these are the units that we need emissions for. So about 1,800 Megawatts here of capacity, located basically within the LA Basin. The Sentinel plant is in Palm Springs. Some people do not think that is in the LA Basin, but as far as the AQMD has assumed, it is in their jurisdiction, so it is actually considered sort of in-Basin. They are almost exclusively -- the El Segundo Re-power has a little bigger turbine, it is a combined cycle plant. The others are LMS 100 units, and if you are not familiar with those, they are about a 96-97 Megawatt nameplate rating, under peak load conditions, probably 93-94 Megawatts a piece. They are small units and, in essence, have small turbines, and do not provide the same level of inertia, but they are in the Basin and they will have some value in popping up voltage and some things like that.

COMMISSIONER BYRON: Now, if you could, just for a second, I would like to just take a moment and go back and ask a question -- why did you sign the contracts -- those four contracts for those four units? What is the basis for the selection of them? Why do you need that power?

MR. MINICK: Okay. In the last LTPP Proceeding at the CPUC, we looked downstream and the CPUC determined that we needed some new steel in the ground. There is sort of two ways of looking at our load requirements, one is a contractual look, do we have enough contracts to get by and are there sufficient resources to contract with. The CPUC determined in that proceeding that we probably needed some new steel in the future and, again, this is before the great economic meltdown. And so they said, "We want you to go out and sign up to a certain level of 1,800-1,900 Megawatts of new capacity." We went to a new resource solicitation, we got many bids for that solicitation, and then chose these resources based on a net present value of the resources that we were basically looking at, and took the ones with the best net present value to fill that resource need.

COMMISSIONER BYRON: Okay, and do you know where the 1,800-1,900 Megawatt resource requirement came from?

MR. MINICK: It came from the LTPP Proceeding, as directed by the CPUC.

COMMISSIONER BYRON: Well, I am trying to get you to say the Energy Commission because we do the demand forecast -- we do the demand forecast, of course, that the PUC relies upon for what is needed in the various service territories.

MR. MINICK: Yes, it was your forecast and it was some other assumptions on retirements, and I build the table, so I know what is in the tables. So it was basically a concerted effort by both regulatory agencies to try to figure out what at that time we thought was our resource need.

COMMISSIONER BYRON: Now, you mentioned the economic meltdown, so are these units still needed?

MR. MINICK: I guess you are asking me to agree with David's table. I will not totally disagree, David and I are friends, and we have worked together a long time. His assumptions are not totally unreasonable. It is the first time I have seen it, I am going to have to go back and dissect it a little more, but I would expect to come to a similar conclusion. I think the driving force behind building new resources will be the retirement of the once-through cooling resources, since the timing issue. Where Dave said they will not retire until the date shown in the Draft Water Board Policy, I am not sure exactly -- and I am not an expert on that -- how that policy is going to play out. Some of those plants could likely retire before that particular end date, and so I think they will be a driving force on the availability of those resources to shut down, but it is also this inertia issue. So if I have to build a few more resources early to cover an older resource that retires early, that cold also be in play.

COMMISSIONER BYRON: Good. Good answer.

MR. MINICK: Now, we tried to take a look at this issue on PM-10 credits is how much do the resources have to buy, and what do you think they are actually going to produce. So we tried to do some modeling, and I have already been warned by my staff at Edison that I said we used our own internal load forecasts, so let me say, it is not something hidden, I simply used what was called Edison's spring forecast this year, it is slightly higher than our September forecast that you have all seen, I think, this week possibly, so it is not a terrible forecast, it is a little bit higher than, I think, the CEC's, and our current forecast, but it is in the ballpark. The purpose for this analysis -- and this is not to say it is absolutely right, it is to try and say how do we think these resources might be run on our system, so we did look at all these factors, we updated some RPS assumptions throughout the WECC, so we raised some requirements in other states, so they built some renewable resources, so in many cases building more renewable resources in other states simply mean other states are generating more power, and we might have less imports, or we might use our own resources less because there is surplus in the market. So we used a model that many people have used we used a WECC-wide, meaning we dispatched the entire WECC to see how these resources might be dispatched under market conditions in the entire WECC. We did not shut down a significant amount of once-through cooling plants. You will see here, we said about 3,000 Megawatts by 2020, this is about half of what is actually out there, but we did not think we could necessarily assume they could all be shut down forever, or should another reason, so these are the assumptions we used.

And the next page sort of tells you how these plants were operated. And, again, this is just a one snapshot look. I do not expect these numbers to change radically because these are peakers and there are lots of energy and resources out there to import as long as we have in the inertia to import it. So what you see here is modest capacity factors for some of these resources, around 20 percent max, and you will see that the PM-10 equivalent offsets that we typically need, if we said that we can perfectly forecast our offsets, are about 670 pounds. Based on what the rules are, if they do not want to be restricted in their operations, they are going to need to buy about 2,000 pounds. So there is a significant difference between what they need to buy under the regulations, and I am not an expert on regulations, but we can talk to the AQMD if you want to get into the details of that, I just have been told by my people that that is about what they are going to have to buy. But they are only going to produce 670 pounds.

Now, what do we need to do to determine future resource needs? A whole bunch of things. We need to do resource planning studies changing the RPS scenarios, the type and the locations of different RPS resources, how much is geothermal, how much is solar, what kind of solar, whether it is solar thermal, as Dave said, solar thermal gives you some inertia, solar PV does not give you any inertia. We have got to look at changing load growth and electrification and DG, meaning how much in-Basin generation will be built, how much is CHP, how much is solar. Electrification is a big driver because that is going to raise our load in the Basin. We are just starting to do these things. I would expect to have us do a lot of these studies in the LTPP Proceeding next year. I expect there is probably going to be multiple scenarios, meaning probably at least three, four, or five different scenarios, with different sensitivities with some of these variables. All of those will give us a slightly different answer, so we will have a pretty good range of what might be expected. To date, the LTPP has not done transmission planning. In this particular LTPP proceeding, we are probably going to start doing much more rigorous transmission planning as part of the overall process. We are going to have some voltage for instability and other violations from WECC and their standards, so we are going to have to take a strong look at exactly what is happening under these cases and seeing if we can find transmission solutions to make the grid work. And then, also, we have good operability studies which means how much ramping do I need, how many ancillary services, can they cover ramps, can they cover contingencies and operating issues. That has all got to be studied. We are starting now. I look at it to be a year or two of significant studies with us, your staff, the ISO, and many other parties that are probably going to get involved.

So the conclusions are, we cannot tell you right now how, what the dispatchable needs are and the in-Basin needs are to make the system work. We have started the first phase of this ISO study, I think they will probably be doing a Phase 3 next year getting into more detail. We do know the LA Basin needs some inertia to import, we know we need to import either from out-of-state, or just the renewables that are in the desert, so if we do not have enough inertia, we are going to have to find transmission fixes, and right now I cannot say we have identified or solved all those transmission fixes. And then we have to do significant transmission planning to figure out what the grid needs to be, and how robust it needs to be, to be able to import all this renewable power, or use distributed generation in the LA Basin to solve some of the load issues.

COMMISSIONER BYRON: One question. This has to do with this fact that we are all joined here by a number of issues, including once-through cooling, this prior reserve issue, as you know, as I mentioned earlier, the State Water Resource Control Board is going to promulgate their rule, they indicate, by the end of this year; none of us is an expert on what that will end up being. But we are going to need to work closely together in terms of how we figure this out. You have got a lot of analytical capability, a lot of information that is included in these studies that you will be doing. Maybe you are not the right person to answer this question -- will you share that information? Can we have access to that, so we can evaluate it and do this in a transparent way?

MR. MINICK: Absolutely. Everything we are doing, I see very little that will be held back. I agree with Dave that there are certain ISO operating procedures that have to be kept confidential, but all our results will be made public.

COMMISSIONER BYRON: Good. And more than results, I think we need to really -- our staff needs to be able to dissect, if you will, a lot of the assumptions that are involved. As you indicated, you may use a different demand than we use, so I think I am asking, really, will you open up the books so that we can see the assumptions, not just the results that go into this kind of analysis.

MR. MINICK: Absolutely, unless I am in violation of some confidentiality issue with the ISO.

COMMISSIONER BYRON: Well, and these confidentiality issues, I think it is incumbent upon us as state agencies, and even the Independent System Operator, to make the case for why something is confidential. It is just not acceptable to say it is a national security issue, but that is not your problem.

MR. MINICK: Right.

COMMISSIONER BYRON: Mr. Minick has always very informative, a lot of information, short period of time. Will you be here for the rest of the day?

MR. MINICK: Yes. I am on the panel.

COMMISSIONER BYRON: Good, because I am hopeful that others will have good questions for you. Commissioner, do you have any questions?

VICE CHAIR BOYD: No, thank you.

COMMISSIONER BYRON: Thank you. Ms. Korosec.

MS. KOROSEC: We do have a couple of questions on the WebEx. First, again, from Bruce Rising. Can you open his line for us?

COMMISSIONER BYRON: Mr. Rising, go ahead, but we are really looking for clarification, I think, at this point.

MR. RISING: Yeah, I am looking for the definition of the term inertia. Is that another way of describing voltage support?

COMMISSIONER BYRON: Good question, good question.

MR. MINICK: It is not just voltage support. And, again, I am not a transmission planner. Inertia gives your system the ability to respond to electrical disturbances on the system, equipped enough so that you do not lose the whole system when it goes down. So it is actually bars, how many bars can you provide into the system.

MR. RISING: Are you using the existing infrastructure? Are you running those units -- like the Scattergood and Haynes, with synchronous condensers, at times?

MR. MINICK: No, I am not running anything as a synchronous unit. That might be one option is to convert old steam plants to synchronous condensers. That could be a solution to some of the issues.

MR. RISING: Okay. Thank you.

MS. KOROSEC: The other question is from a gentleman who is not on the phone, but I will read the question here that he sent in. "Why did we need contracts for Blythe and Otay Mesa then? Aren't we paying too much under contracts for these projects since the financial market collapse?"

MR. MINICK: Well, first, the Otay Mesa contract is not an Edison contract, so I would prefer to not answer questions about that one. The Blythe contract, in essence, was the lowest cost option in our solicitation, so we think that is one of the more cost effective resources that we could have purchased.

COMMISSIONER BYRON: I think we have one more question? All right, thank you very much.

VICE CHAIR BOYD: Yes, thank you. Very informative.

COMMISSIONER BYRON: I believe the next presenter is Catalin Micsa from California Independent System Operator.

MR. MICSA: Good morning, everybody. My name is

Catalin Micsa. Good morning, Commissioners.

COMMISSIONER BYRON: Good morning.

MR. MICSA: I am here mostly to talk about these location and capacity requirements for the LA Basin in the ISO controlled area. I can try to address some of the other questions there were here before. I apologize, I cannot do anything about some of our operating procedures. They had been hardly reviewed by legal, FERC, and other entities, and they are divided in, some of them, on market and they are posted on our websites. If they have an "M" number, they are market, and anybody can see what is out there; for example, Southern California Import Transmission, SCIT, it has market pieces, you can go look on the ISO website what it is about, and there are some other pieces of it that are market sensitive, and we are just not publishing out there now. Here, the way I looked, this is an ongoing process and we are looking many years ahead, and once we do some more studies, we probably are going to be able to make those results available to the public. What is really market sensitive is what is building right now because, you know, the generators and the load they are bidding day in and day out, and that is market sensitive. To me, it is nothing that you want to do 10 years from now, it is not really that market sensitive. So once we start doing some more of those studies, I am sure that we can probably release some of the results.

COMMISSIONER BYRON: Yeah, Mr. Micsa, I do not want to be misunderstood, either. We are not accusing anybody of hiding the football. I am really interested in making sure that the public, if it is not completely transparent, they understand why information is not being released about an operating procedure or market sensitive information. And I am just saying, we have the obligation to make that explanation.

MR. MICSA: Right, and we are replying that, once we go through more workshops, I am sure we are going to have some more next year and the year after that, in how do we implement, you know, the shutdown of the once-through cooling, if that is what people want to do, because personally I would really like to see how the generation community responds to what the Water Board put out there and how they want to comply with that, for us to be able to make a plan --

COMMISSIONER BYRON: Yes.

MR. MICSA: -- a scheduled plan of implementation. So we are going to have some more discussions in the next couple of years. Personally, I just do not want to get into a situation -- it looks like right now there is some ruling in LA Basin, at least to have a plan to achieve a goal. I do not want to get into a situation like I had today, for example, in San Francisco, or San Diego, where we are fighting for every 10, or 50, or 100 Megawatts in order to keep the NERC mandatory standards in compliance, and stuff like that, so trying to avoid that by being proactive and having a heads up approach to how to deal with all these issues together. There are many issues, not a single one, as you pointed out.

I would like to just briefly talk a little bit about research adequacy and how this fits in. Basically that gives us resources available when and where needed, they have to be under contract. Most of you already noticed the generator usually makes a showing in the month ahead with 100 percent of what the procurement is in a year had to make 90 percent system and 100 percent local. They all have a must offer obligation to the ISO. The problem is, if we do not have our contracts, the units we usually do not have, we do not have FERC must offer anymore, the ISO, so they are not really obligated to bid into the ISO market, it can just shut down the unit and we will not be able to dispatch it.

What is the ISO ruling here? We do the review of these bodies to make sure that all the existing fleet and a new fleet coming up gets deliverable to the aggregate of loads, so basically it has an opportunity to exit the pocket they are on, and get into the main heart of the grid. Also, we look at the locational capacity requirement based on our

FERC approved tariff. We do all the studies regarding the location of capacity, and we actually allocate the responsibility of that to the load serving entities, and then it is their choice if they go buy it or not, and we do have a backstop procurement if not enough capacity is made available in these local areas. More so, we also do the RA import allocation, basically we allocate imports coming into the ISO control area based on FERC approved tariff. And, of course, we ultimately do the operation of the grid.

The Resource adequacy procurement, you can see that on the bottom, usually the way we think about it is you need some local resources in order to reliably operate the system based on the NERC, WECC, and ISO standards. Then, beyond that, you can pretty much buy any units you want, anywhere in the system, and those are very flexible and you can just buy for one month, or whatever. The imports are allocated, again, based on our methodology, and we also have the minimum locational capacity, so basically the ISO mostly does this portion over here, and this portion over here. And the state and other local regulatory agencies, they do this portion over here.

What are the local capacity requirements? It is basically we have this local area, it is very limited on what you can import in. When I am saying "very limited," you cannot import enough to serve all the load, you have to have some local generation in order to meet the standards. Now, the way we do the study is we have a 1 or 10 peak, so it is basically a summer or super hot peak, we will maximize the transmission coming into the area. We assume everything is in service, and then we take the required contingencies, but basically everything is available to us, and then we just -- we give out the number of minimum local resources that need to be purchased in order to meet that. And the assumption is that all of those resources will be available, so, again, 100 percent of those resources will be available to the ISO.

Currently, there are two local areas across the ISO grid, as I said, in Northern California, and through the Southern California. The LA Basin is the biggest local area.

COMMISSIONER BYRON: Excuse me, just a quick question. So when you say you maximize transmission imports in your analysis, is that pretty much the number from the table that Mr. Vidaver had? He showed about 10,100 Megawatt net imports, so are you assuming a larger --

MR. MICSA: In essence, that assumes about the same thing, but we are talking about two different issues here, the data put out there is regarding to the Southern California import transmission, is the entire Southern California. Let me refer to this map. It is something on this magnitude over here, something like this, it is the entire Southern California. Mostly what we do in the locational capacity, we go on smaller areas than that and we have defined -- the LA Basin is defined with this black marker over here, and then we have Big Creek, Ventura area that is somewhat defined as this area over here, we also have San Diego, which is just down here, these outskirts, as local areas. If you think about them, they are smaller areas inside the big system.

COMMISSIONER BYRON: Right, more discreet.

MR. MICSA: More discreet.

COMMISSIONER BYRON: And, as usual, always more complicated than a simple table indicates.

MR. MICSA: Usually, yes. So our defined elevation, you pretty much have this black oval over here. We do have -- most of our requirements are kind of split in two and you have got to see from -- there are slides I have in the future here that there will be differences in requirements between the western part, which is this part over here, we consider that as being the western part, and we consider this area over here to be eastern part. They are cut somewhere around here. I am not going to stop much here. The 20,000 Megawatts is about this local area, it is a humongous local area. Available resources to date are close to about 12,000 Megawatts or so. You have the worst contingencies in the western pocket, which is close to 5,000 that we have for 2010. The overall -- what is important here is the overall LA Basin is close to 10,000 Megawatts that are needed in that area. So under the 12,000, we need about 10,000 currently. This is in 2010 studies. Now, this is 2011 -- 13,000 -- we looked out five years, you can see the load is growing up a little bit. The resources assumed that we will be growing up. Of course, some of those new resources that were assumed in there require new air permits. Also, it is important to note that, in our future studies, we do have some transmission. We did model Palo Verde-Devers 2, that one, as we all know, got stalled for now. Rancho Vista is moving far along. And the Tehachapi project is moving far along. The Vincent-Mira Loma is part of the Tehachapi, so we expect that to be done around 2013 timeframe. You know, LADWP can speak for their Green Path and Norton, what situation that one is on.

If you consider this project as being available, then if you look to the future, you can see that the western area requirements actually is going up every year. It goes from 5,000 to 6,000, and it goes to 8,000. Now, you can ask yourself, that is a tremendous increase in number, first it is below growth, we do not disagree with that. And there is a good reason for that. The reason is the LA Basin overall is decreasing, and you can say, "Well, what is going on here?" So I am going to explain a little bit about this. You can see in 2011, it is 10,000 Megawatts, and all of a sudden what we are saying is that basically what is going to be left after that will probably be this 8,500 over here. Now, what is happening is these approved projects that we have over here, for example, some of the major projects that are allowing us to import more power into the LA Basin, Palo Verde-Devers 2, yes, but most importantly, Vincent-Mira Loma 500 kV, and even Green Path. What this project is doing is actually, the way it was approved by the California Public Utilities Commission, is taking some of the old 230 kV lines and they are operating them to 500. Now, once you do that, you increase the entire imports for the LA Basin, so those are -- the requirements are dropping significantly because you are bringing in new 500 kV line. But I can probably explain better in this drawing right here, so what is happening is we have a new line that is coming down, a new 500 kV line that is coming down this way, but once it reaches this area over here, it is very hard to permit new 500 kV lines, as we all know. They are taking pieces of the old 230 kV equipment and they are operating it to 500, and now all of a sudden you have got a lot more import capability in the entire LA Basin, but by the same token, because you took those 230 kV lines out, you have decreased the imports into the Western LA Basin. So basically, the reason why everything is dropping is mostly because of these transmission projects, and the reason why the Western LA Basin is increasing is because of the same projects, because they are taking lines out and we do not have them anymore.

COMMISSIONER BYRON: I am a little confused by that. You are taking lines out. That is not correct. You are doubling the capacity of those lines.

MR. MICSA: That is correct, but it does -- so overall, there is a great benefit because you see we are going from a requirement of, you know, 10,000, then in 2011 we go a little bit beyond 10,000, and all of a sudden the LA Basin decreases to below Western, so really the overall numbers are going down. If you look from an overall perspective, the number is going down from 10,000 to 8,500. Because, really, the eastern area will probably have close to no requirements, okay? So if you look from this map over here, we are increasing the overall import into this whole area, but by taking transmission out of this sub-area, this sub-area becomes even more constrained than before, so the requirements for this sub-area is going up, and at the same time, the requirements for the entire LA Basin is going down. The net effect is that everything goes down. It goes down from 10,000 to 8,500, so we are doing a good thing here, we are saving 1,500 Megawatts of local generation. Except, today that can be met from either East or West.

Tomorrow, all of that has to be met from the West because we just took those lines out and we need to rely heavily on the western guys versus the side.

COMMISSIONER BYRON: It sounds like we are making a mistake.

MR. MICSA: Overall, it is not a mistake, but just -- if you look from a Western area LA Basin perspective, it is a mistake. Now, there are some other projects --

COMMISSIONER BYRON: Well, that is not -- because in the west is where we have all the once-through cooling plants.

MR. MICSA: So if you look from the once-through cooling perspective, it is a mistake. But if you look from an overall local capacity perspective, it is a benefit. Now, let me just go a few more slides here because we do have more projects beyond that. I am going to come back and talk about this, but if you look further down the road, we just finished these studies about two weeks ago, and we published on September 15 on the ISO website. There are some additional projects beyond those that we start in 2013, and they are supposed to be coming in 2014 or so timeframe. Some of the remaining lines are getting re-conducted, so once you do the next phase, that 8,500 Megawatts, it is going down again, it is going down to 6,700. See, we started around 5,000 for the West, then we went to about

6,000, then to about 8,000, and the next year we go down to about 6,700. Additional projects are needed beyond this to decrease this number further. Today, we do not have anymore projects that are approved. We are working with Southern California Edison and all the market participants to see what additional projects might be needed beyond that.

Okay, so I would just like to talk a little about the real time operations. We go and we define all these local areas, and then that is the minimum generation that needs to be purchased in that local area. Now, how you actually dispatch those units in real time is a combination of things. We use security constrained OPF and basically the least cost generation comes online given that we need to comply with all the transmission constraints. Now, when you say, well, what are the minimum daily constraints, and Mark had a table here, and David tried to put up there, and it said it is market sensitive and we cannot really put it up there. Basically, it is driven by a low forecast, it is driven by transmission generation out-of-service. We do not have 100 percent availability of every equipment in that area at all times, so it depends on which ones are available at any given point in time. Also, as we talked before, it is very important that they actually get those imports. We talked about the 10,100 number, that is for the entire Southern California coming in, and that nomogram -- it has a inertia component, and when you think about inertia, think about it as a relation of mostly mass, you know, how big the generator. Yes, technology has a lot to do with it, too, but just a short assumption is, the bigger the generator, the more mass it has, the bigger the inertia, and it is very important that we have inertia to allow for the imports to come in from Arizona, or Northern California, or some of these remote areas it has to come in to the Los Angeles Basin. It is important that you have inertia, and it is available.

Now, if you are talking, "Can we actually just replace that with peakers?" Because I have heard people asking about it, well, we see some of these existing generators that have a very low -- not an availability factor, because the availability factor is very high, but actually how much they run. They do not run that many hours. So why don't we just replace them with peakers? Well, for one, it is not the same thing. Inertia is a really big driver. We tried to replace with peakers, we have small or renewables which have most of the neglectable inertia. We are going to need a lot more generation than we are retiring, so, you know, we do not know what that "a lot more" is right now, but it is probably five times the amount, we do not know what that is because we just have not done the studies. We will be doing some more studies, one for ramping -- we talked about ramping -- we are going to do some ramping studies for renewable integration for 33 percent. I believe by the end of the year, we will be able to publish a report on that. And that will just mostly deal with the ramping issues. We have not tackled yet the inertia issues, we probably will tackle that next year in our next assessment, so we can give you a better picture about the inertia issues.

The transmission system, it is very dynamic, with a lot of unexpected twists and turns. Also, the existing fleet, it is permitted to run year-round. Yeah, they are not running that much, but it is permitted to run. So the new peakers that we see coming out, most of them have a very limited number of hours, permits run, I do not know, maybe 500, 1000 hours a year. Well, you know, if something happens and Diablo goes out for a month to be refueled, you can burn out more than 500 hours on a peaker in one month, and then what do you do for the rest of the year? So we might need to permit a lot more peakers in order to cover more time of the year because each one of them will be permitted for less number of hours. Well, if you do that, my personal opinion, you just spend a lot more money in putting a lot of these on that have smaller amounts of time that they can run, so probably it is advisable that we use some base loaded plants, more like combined cycle, something that are permitted to run more hours, even though, if they do not run, and they do not put any NO_x emissions in the air, well, great, but at least they should have the flexibility to be available because otherwise we can run into some troubles and we do not want to get into low shutting.

COMMISSIONER BYRON: Well, that is great from an operator's perspective, but having the Emission Reduction Credits is really the issue that we are dealing with.

MR. MICSA: Right, and I do not know how to make those available, that is why we are all here, to talk about all the issues we have. I am just hoping that we can make a plan to go from where we are today to where we want to end up five, six years from now, and that we can meet all of the standards without violating the ones that we are here to speak for, which is the mandatory NERC standards. But we understand, you know, the once-through cooling issues, we understand the air permitting issues, we understand all this stuff, and we are trying to work with everybody to achieve all of their goals. The only reason we are here is that we can plan -- allow us the time to plan and tell us all the requirements that you would like to see, and some of these are brand new, you know, like the once-through cooling, bringing in requirements, even the staff in California Air Quality District, who are there for a long time, they just, you know, because of the loss, like you said, the loss and that other thing that happened here, they are new developments. As long as the new developments allow us the time to plan, I think we can do a pretty good job of that.

So in conclusion, from a local capacity perspective, we see the long term that the LA Basin will most likely we illuminated the way you know it today. We will form two new local areas, one will be called Western and one will be called Eastern LA Basin. From what we can tell today, all the resources that will be connected to Devers, and there are a lot of renewables connected to Devers, it goes through Palm Springs, and those will be outside of the local area. Upgrades west of Devers are expected, you know, we fully expect that we are going to see some of that. Also, beyond that, as you said, our biggest problem, like you acknowledged, Commissioner, is the Western LA Basin, and that will require new resources, and I do not know how to get around the permits for those, or new 500 230 kV transmission projects, and we are saying we are expecting at least two or three new 500 kV lines in the area, you cannot just build one because if you lose it, you are back where you used to be, so you need at least two or three to account for contingencies. That is not easy to permit through that area because it is densely populated, too. There is no silver bullet here, we did not come with a silver bullet today, we acknowledge there are all these balls in the air, and somehow we are going to need to plan to meet them all, and we are here to play and get the planning going. We expect that, you know, all of these can be met somehow, we just need to reach the conclusion how, and to be able to plan them along. I always say I would like to see -- all the generators like to complain -- to see the plans from the generation community, how they are planning to comply with the Water Board regulations for us to be able to plan because we cannot allow our plan to shut down first. The preference should be given to power plants who want to repower. If somebody wants to repower and they want to go and destroy the site and rebuild on the same site, they should get priority of shutting down first, versus I shut down and it is not really permanent, because if I shut down somebody permanently, I cannot allow the other person to shut down to meet and we will decide because it takes longer than one year and we have to go through at least one summer. So priority needs to be given to people who would like to repower versus people who would like to shut down. That is why I say it is very important that we plan these things out through the years, how to reach compliance with not just the Water, but the Air Quality Emissions and all that stuff. If anybody has any questions.

COMMISSIONER BYRON: Very good. Thank you. I am glad you are here. A lot of information. Dr. Jaske, I am glad you stepped up because my singular question is to you, and to Mr. Vidaver, and to staff. I find this very complicated. I do not understand everything in this presentation. Have you digested this recent ISO study? Do you understand all this material?

DR. JASKE: I understand what he is saying, I do not think I understand all of the steps he has gone through to get to his conclusion. So, as you observed earlier, we will be at this for quite a while, and our various speakers so far this morning have indicated that some of what they are talking about is preliminary and needs more study. And if there is going to be any refrain throughout this day, probably, it is that we need more study. And the analytic side of the industry has not yet done all it needs to bring forward to the decision makers the choices. That is still a ways off.

COMMISSIONER BYRON: It kind of -- yeah, Commissioner Boyd is whispering here, too, it does make it a little difficult for us to public recommendations in an Integrated Energy Policy Report.

DR. JASKE: I believe Ms. Korosec said it correctly. This IEPR will be able to give a status report and frame the issue, it is not going to solve it.

I do have a question for Mr. Micsa, which is why I came up here. Could you show slide 17, please? An important point you made about slide 17 is that the Western LA number in 2020 goes down to 6,700 or thereabouts. And you said that was a result of the transmission system upgrades on the previous slide 16. And I thought I heard you say, but it is not written down, that you expected some of those projects to actually become operational before 2020. Did I hear you correctly?

MR. MICSA: Well, these projects are actually supposed to be operational in 2014 and 2015 timeframe.

DR. JASKE: And so my basic question is, has the ISO sort of done a year by year analysis that shows when that sort of the schedule on which the Western LA Basin number diminishes as either individual or groups of these transmission lines come in to service?

MR. MICSA: We already have the results for 2010, 2011, 2013 and this long-term one. We are working right now on 2012 and 2014. So before the end of this year, we will have '10, '11, '12, '13, and '14, for sure, and we actually have a vision for 2020. So I think we have quite a lot of numbers to look at from a locational capacity perspective.

DR. JASKE: Okay, but from an OTC power plant retirement scheduling process, it is knowing when those transmission upgrades happen that allows the timing for the retirement or the down time for repowering for those OTC facilities.

MR. MICSA: That is very very correct, so the timing of the transmission projects and the timing of the generation proposals to repower versus retire is very very important, and we have most of the timelines for the transmission. These are all approved projects that we are talking about. For these ones, we do have all the timelines, and we can write it down for you if you want to. What we do not have right now is we do not have the other equation about what the generation community wants to do, and we would like to see that so that we can put the two together and have a master plan, of how to get from here to there.

DR. JASKE: Well, but also there is a perspective of having the transmission plan, or the ability to move transmission projects around so as to influence what the generators want to do.

MR. MICSA: That is correct. And once we are going to have both sides of this integration, we can put them together and see if we need to get some projects done faster, or we should postpone certain generation retirements, and whatnot, in order to accommodate all the schedules. I am not saying it is going to be easy, I am just saying some of these transmission lines are approved, some of them are just approved by the ISO, but then maybe the routing is not approved at the PUC, so we need to all coordinate between the California Energy Commission, the ISO, and the CPUC, how to get the plant going.

DR. JASKE: Right. Thank you.

COMMISSIONER BYRON: You know, if it were just those two factors, balancing the generation and the transmission side of this equation, I think we could figure it out easily. But, as we know, there are a lot of other factors involved here.

MR. MICSA: There are a lot of factors, and we will have some response for you regarding the ramping needs, especially for 33 percent integration, by the end of the year. Now, we have not started yet on inertia. We are planning to do that in the next planning cycle, which is next year. That is all we can do.

COMMISSIONER BYRON: Absolutely. Mr. Micsa, it is great to have you here, to have a transmission planner from the ISO, very valuable to get into the technical details. I can also tell you, at the highest levels in the organization, we are working closely with the PUC and the ISO to address all of these issues in a more substantial way, particularly around the once-through cooling concern. It is not just going to be a transmission fix or a repowering fix, there is a lot more involved in all this. So we look forward to your analysis, I hope you will be as forthcoming with the information as you can, again, for a lot of the same reasons we were discussing around transparency, but also for our staff to be able to evaluate all this information as sort of, if you will, the balancing organization around the environmental transmission generation issues. Sir, would you like to identify yourself?

MR. TURNER: Sure. Mark Turner with Competitive Power Ventures. I have got a clarifying question for slide 15. When you mentioned that the peakers usually have higher energy costs and/or are more polluting when they are operating, my understanding is that, you know, the peakers that are coming online have intermediate type peak rates, they are extremely more efficient than the boilers that are existing on the coast. And, in addition to that, in order for the boilers on the coast to provide the services that they are now providing, they were not really designed to do that, they are not able to come up in 10 minutes like the new peakers do to provide the ramping service. They are needed to come online on a day-ahead basis, so they are basically left on during the night in order to provide those services. So I do not know if that fits in with your last bullet?

MR. MICSA: Our ramp rate was not -- I apologize for the wording here -- but we did not really mean to compare the new peakers with the existing fleet. We meant to compare with the new peakers versus new more like base loaded, so new versus new, not new versus old. You compare old versus old and new versus new. We are not trying to compare new versus old. So if you just look from that perspective, probably a new peaker, probably that is true, but we make it easy.

MR. TURNER: So as I understand it, the opportunity cost is, you know, what you need is new ramping resources that come up quickly. So that is the services that the OTC units are providing now, and if you compare with the alternative is, which is basically new peaking, it is actually much more efficient to use the new peakers with their, you know, 9,000 heat rates quick starting capability, no need to keep them on. It is much more efficient from an environmental and energy perspective to use those plants.

MR. MICSA: It they would be permitted for just close to about the same amount of hours and we would not have an inertia problem, I would totally agree with you.

MR. TURNER: Right, thank you.

COMMISSIONER BYRON: Right. Inertia, grid stability, and ramping, there are a lot of factors at play here. Sir, thank you very much. I think we will go ahead and press on. I think we are doing pretty good on schedule, Ms. Korosec, are we?

MS. KOROSEC: I believe so. We have one more presentation before lunch from LADWP.

COMMISSIONER BYRON: Good. I show that we have Mr. Kenneth Silver from Los Angeles Department of Water and Power. Mr. Silver, we have not met, however, I heard about you. I am very glad that you are here today. We know that Los Angeles Department of Water and Power has a number of plants in this area, and are very concerned about the same issues that we have been discussing with Southern California Edison and the ISO. We welcome your input and thank you for being here today.

MR. SILVER: Well, thank you. I am glad to be here. I am the Manager of Energy Control and Extra High Voltage Stations. I am not a Transmission Planner, I am a Reliability type person. So I will be speaking from that frame of mind.

COMMISSIONER BYRON: In fact, if I could, this is one of the only presentations I do not have. Do we have copies of this, Ms. Korosec? Thank you. Please go ahead.

MR. SILVER: Yeah, we were not aware that -- we brought it up with us today, we were not aware that they were to be hand-outs. I apologize for that.

COMMISSIONER BYRON: That is all right.

MR. SILVER: Briefly, I am going to talk about -- give you an overview of the Department system. You are probably aware of reliability criteria, but I just want to touch on how we use reliability criteria, determine our requirements, a brief evolution of the LADWP transmission system, why local area generation is needed, our present and future requirements in jittery general terms, and opportunities for transmission upgrades.

LA is a vertically integrated utility, so we do have the benefit of owning most of the transmission and generation that we use. We have a mix of generation in the Los Angeles Area which is primarily gas-fired and hydro-electric. Externally, we import a wide variety of resources, coal, nuclear, hydro generation, we also take advantage of our transmission system to bring in energy from the Pacific Northwest and elsewhere on the WECC system. Generally, large scale renewable energy will be coming in from outside the Los Angeles Area, and when I say Los Angeles Area, I am talking about the City of Los Angeles, not as the ISO refers to the LA Area. And this will have to be brought in our import transmission system.

And the genesis of our system is that the generation was strategically located for reliability. Our transmission internal to our system is a network of 138 and two 30 kV lines and cables, and then we have an external network of 287 kV, 500 kV, and high voltage DC that we use for importing power to the system. In our transmission system, as you will see a little later, is somewhat of a belt loop that we use for moving power around the city.

In reliability criteria, LA, like all of the utilities, are required to meet the reliability standards set forth by NERC and enforceable by FERC. The transmission reliability criteria that we basically follow is that sufficient generation be online or immediately available to meet some criteria. The first is sufficient appropriately located generation must be online, and producing energy so that pre-contingency, meaning normal operation, all of our circuits are loaded within their continuous capability, and all of our voltages are normal, and that following a contingency, which can be a loss of a generator or a line, that no circuit would be loaded beyond its emergency rating and that voltage settles out of at least 95 percent. Secondly, we have to have sufficient appropriately located generating capacity that is either online or available in a short period of time, such that we can offload circuits that might be overloaded following a contingency back to their continuous rating, and also returning the voltage to normal.

The evolution of the DWP system -- in the 1940s through 1960, Los Angeles was experiencing rapid load growth and local area gas-fired -- or, at the time, gas and oil-fired generation -- was constructed mostly along the coast. And the LADWP transmission system was constructed to transmit that power from those primarily coastal power plants to the growing load centers inside Los Angeles. Then, starting in the 1960s and presently, we began participating in jointly operated power plants that were remote from the City of Los Angeles, and also accessing the low cost energy which was available from the Pacific Northwest. We built a large high capacity transmission network to bring this energy into the City of Los Angeles, however, most of those tie lines tie into the northern part of our system. This under -- as the load goes up, this can create a very high north to south flow on our in-City transmission system, above what it is capable of carrying, and that is why we are required to run the coastal generation to offload those circuits, and basically supply the local area demand in that part of the city. This reliability generation is required year-round, but obviously the requirement increases as our load increases.

A quick diagram. In 1949, you can see the genesis of our system. At the very bottom, you can see our Harbor Generating Station, our first coastal plant, feeding our system. And then, in 1959, our system was rapidly developing, we were adding additional generation, adding additional receiving stations, which are high voltage substations throughout the city, we brought in some power from the Owens Valley, and added the Valley in Scattergood gas-fired plants.

COMMISSIONER BYRON: That is the SCA over on the left-hand side?

MR. SILVER: That would be Scattergood.

COMMISSIONER BYRON: Thank you.

MR. SILVER: And at this -- this is the point where this pattern began the form of importing in the north and generating in the south. By 1975, our system was at a point where it generally exists today, we have made some additions, some upgrades, some modifications, but really the basis of our system's existence since 1975. We added, again, some additional stations. We began importing coal-fired generation. The operation of the Pacific DC Inter-tie, and added our Castaic Pump Storage facility, and at that time, the Haynes Generating Station was also built. Again, importing from the north and generating in the south.

This is our 2009 system, and the big addition is all external to the system, so we are bringing in -- as our load has gone up, we are bringing in -- more and more energy is being imported. But, again, the transmission is not capable of moving that all the way from the north part of our system to the southern part of our system.

COMMISSIONER BYRON: Mr. Silver, before you leave that screen, there are 60 years of transmission and generation just re-condensed into one slide in two minutes. A couple of basic questions. Is your system completely independent? Can it operate independently of the surrounding grid?

MR. SILVER: To the standpoint of serving our load, not talking about the resource that serves it, but serving our load, our in-city transmission system serves our load, we are not dependent on any of that. But our external transmission system is closely linked and intertwined and overlaid with the California ISO transmission and other utilities' transmission. So from that standpoint, we cannot pull that out and separate ourselves from other utilities. Most of those large resources -- all those large resources that we are partners in are owned by other -- jointly owned with other utilities, so we cannot just segregate our share out.

COMMISSIONER BYRON: Thank you.

MR. SILVER: Okay. In 2009, we are importing from our Intermountain Generating Station in Utah, Palo-Verde, and we are also beginning to import renewables into the system. As I mentioned earlier, most large scale renewable projects are going to be located outside of the City of Los Angeles, so while they may fit into the Los Angeles area from a broader term, from our imports, they may look like an import just like something from the Northwest or Arizona to our system.

The kind of hard to read colored diagram is the

City of Los Angeles, and unfortunately it is a little hard to see on the screen, but there is a belt loop system, as I mentioned earlier, of the 150 and 230 kV circuits, and the power from the external system comes in from the north, you can see all that, all those lines there on the top of the picture, that is our import capability. And as I mentioned, the internal transmission system cannot transmit all the needed power to the central, western, and southern portions of our city, all of that import capability enters our city in the San Fernando Valley, which is the northern part of our system.

Why is local area generation needed for reliability? It provides dynamic voltage support. You can put in a lot of capacitors and things to support voltage, but for quick response and dynamic and transient stability, there is nothing better than a rotating generator to provide that dynamic voltage support. The local area generation provides energy needed to maintain the transmission within its pre and post contingency limits. It also -- everybody else -- we have talked about inertia. Now, I am not an engineer, but inertia as I understand it, it is that rotating mass when you have a sudden loss of generation, or an increase of load, or a fault on the system, the system is attempting to slow down and that rotating mass, that inertia, is what keeps the system going in that transient period. Inertia is also needed to import into the general Southern California Area, that SCIT that was mentioned earlier. And also, we operate two high voltage DC systems. High voltage DC systems need a strong robust AC system to work, so if you shut down the generation, you lose what is known as short-circuit duty, it is that ability to -- I lost the words -- the HVDC system has to commutate, or move energy from one valve to the other, and it requires that strong AC system to do that. So if you shut down the local area generation, you reduce the ability to operate the DC, which is the main import path for us.

As far as present and future requirements, we will continue to need to have sufficient local area generation strategically located. As we look at the numbers of what we need, we have to take into account historical and anticipated forced outages and reductions. You know, generation, particularly thermal generation, does have an outage history, and generally not all of your generators are going to be available all the time.

COMMISSIONER BYRON: So would it be correct for me to assume "strategically located" means at the end of existing transmission lines?

MR. SILVER: Well, for the LA system, it is in that southern portion of our system, which is where our coastal plants are. So it is at the end of -- it is at the southern end of our load center, basically.

Because of our requirements, the current generation cannot be retired until an equivalent resource is constructed in the same or a comparable geographic area.

This table shows our local capacity requirements for the summer of 2009. The first column assumes that all of our generating units in our system -- and when I say all the thermal units, the units that provide that reliability, are available, and it sets forth our optimal generation. The first column would be our optimal generation plan. But because of the fact that we know where there is often going to be units on outage, as you move across the table, it describes what the requirement would be for loss of various generators, for loss of the Haynes unit, loss of the Scattergood unit, the loss of a valley unit. To some extent, we can substitute generation from one plant to another, but often times it is less effective, so you would need more generation from the alternate area than you would from the primary area. And this dispatch is optimized because we have a variety of constraint paths in our transmission system. So this is optimized to have the least amount of generation to handle or offset all of those constrained paths. One important difference is that there is a difference between the capacity, or the amount of generation available, and the energy it is actually producing. And, as I mentioned earlier when I was talking about the reliability criteria, we need to be producing a certain amount of energy at all times. To meet the pre-contingency requirements, we have to have enough capacity available so that we can load that capacity up to meet post-contingency requirements. So, as you can see, the top table is an energy requirement, and this would be for a peak load day in 2009. The top table is an energy requirement, the bottom table is a capacity requirement. The first column there, NOB, is an indicator that is used for the Pacific DC inter-tie, and that is in there to kind of represent the northern imports. And as you can see, with higher northern imports, we have higher reliability generation requirements because of that flow down through our system. So when you increase imports, you sometimes increase the reliability, you cannot trade off one for the other.

On a tabular format, our RMR requirement for 2009, you can see there is a Haynes requirement, a Scattergood requirement, a Harbor requirement, and a Valley requirement, and this would be the optimal spread. The table previously showed the Megawatt amounts, this is showing it somewhat geographically, the red triangles being the generating sources that can supply this reliability energy.

Also, in considering our present and future requirements, we also have to take into account the transmission forced outages. Our transmission is susceptible to failure, as anybody's is. We are vulnerable to seasonal fires, we have had major transmission disturbances twice in the last year due to fires in Northern Los Angeles County. We also have to have sufficient local area generation available to compensate for the forced outage of other generation that might be lost. And we have to have sufficient dispatchable generation to regulate and back-up intermittent resources such as wind and solar.

Our planned repowering projects may change the operation of these coastal generation, but will not have a significant impact on the capacity requirements and the energy requirements during the peak times of the day. Now, what that says is that there are some generators, but they are not cycleable; because we need them during the day, they operate at night because we cannot take them off at night. Under different repowering scenarios, there may be an opportunity to run less generation at night, but repowering is not going to reduce the day-time requirement.

COMMISSIONER BYRON: And just so I understand, it is the design of those old power boilers that do not enable you to cycle them night time/day time. Is that correct?

MR. SILVER: That is correct.

COMMISSIONER BYRON: And that is not changeable?

MR. SILVER: Yeah, that is not changeable. And even some large combined cycles, if you need the units for 18 hours a day, it may not be productive to shut them off because they may only be off for two or three hours before you have to begin your restart cycle.

COMMISSIONER BYRON: And is that also because you are decreasing the life of the plant when you do that kind of cycling?

MR. SILVER: Cycling does increase maintenance costs. If you do enough maintenance, it may not necessarily reduce the life of the plant, but it is going to require a lot more maintenance. And more frequently and more expensive maintenance to maintain the units. Renewables can meet general energy needs, but they do not meet the reliability capacity to require regulation and also the locational needs as I have described.

Opportunities for transmission upgrades. The local area transmission, again, I said was initially constructed to move power from south to north in those early years. The early transmission was comprised of 138 kV circuit lines and cables, with later additions being at a higher capacity 230 kV. There is a limited ability to upgrade the internal transmission primarily due to the fact that Los Angeles is a dense metropolitan area. The available rights of way are pretty much used up, so there is not a lot of opportunity to add additional lines, and only minimal opportunity to upgrade what is already there, to put something in higher voltage.

COMMISSIONER BYRON: And I suspect you have looked at those options, when you say there is minimal opportunity to go to a higher voltage, because most of those upgrades have already taken place?

MR. SILVER: They have been looked at, they have not necessarily taken place because they did not -- they would not have had much impact on the requirements, so it would have been money spent for very little benefit.

COMMISSIONER BYRON: Thank you.

MR. SILVER: We do have a 10-year transmission plan. If the plants are primarily focused on load growth and renewable integration, again, we have looked at opportunities to upgrade in the city transmission; unfortunately, I do not have readily our most recent plan, I was not able to see that, to see how recently we studied the ability to upgrade transmission and reduce that coastal generation, but previous plants show that there was not a lot of bang for the buck, basically.

We looked at plants to upgrade the old 138 kV system, and that was found to be impractical due to the infrastructure constraints. Some of the 138 kV stations are in constrained areas, surrounded by business or residential, and there is not an opportunity to make the station bigger to accommodate more transmission or higher voltage transmission.

COMMISSIONER BYRON: When you say "station," do you mean substations?

MR. SILVER: Substations.

COMMISSIONER BYRON: Yeah, because it is a clearance issue, right?

MR. SILVER: Right.

COMMISSIONER BYRON: And not only do you need to change out every single piece of equipment and re-conductor -- well, you would not necessarily need a re-conductor, but the substations need to be bigger.

MR. SILVER: You need more space; that is correct. Rights of way for overhead transmission are not available. Underground, it is very difficult and costly to install, but in the middle of Los Angeles, it is hard to dig up a street and put in an underground cable on a multi-month, multi-year project. And cables inherently have a much lower capacity than an overhead line does, so putting in a lot of cables is somewhat problematic.

Bruce Moore, from our Environmental Group, is going to touch on some final aspects, and I will be available to answer questions.

COMMISSIONER BYRON: Thank you. Welcome, Mr. Moore.

MR. MOORE: Thank you. Good morning. I will be discussing the Department's Planned and repowering projects and the ERC requirements for those projects.

The Haynes Generating Station in Long Beach will replace two steam boiler units with advanced simple cycle gas turbines. This will result in a reduction in air pollution on a pounds per Megawatt hour basis. The 616 Megawatts of gas turbines will increase the capacity of the facility by 12 Megawatts, gross Megawatts, with no increase in the net capacity. The DWP has already acquired sufficient PM and POC ERC's Emission Reduction Credits from the market to cover the emissions associated with this 12 Megawatt capacity increase. The DWP has applied to the SCAQMD for the Rule 1304 exemption from the ERC requirement offered by the AQMD's rules. The Rule 1304 exemption is an exemption from the offset and modeling requirement for repowering projects that use advanced gas turbines up to the capacity of the units being replaced. In the absence of Rule 1304, DWP would need to acquire over 900 pounds per day of PM ERCs for the Haynes project, and this amount of ERCs is not available on the market at this time.

The DWP is in the preliminary stages of designing a Scattergood repowering project which will replace two steam boilers with gas turbine technology, probably a combination of simple cycle and combined cycle.

The SCAQMD has held a number of workshops regarding the streamlining of its new source review regulations. One proposal is to calculate the ERC requirement on an annual, rather than a monthly basis. The daily ERC requirement for a project is currently calculate by calculating the emissions during the highest operating month and dividing by 30. One proposal made at the workshops is to perform the ERC calculation on an annual basis, rather than a monthly one. This change to the calculation method would significantly reduce the ERC requirement for many projects, particularly seasonal industries like electric utilities where the difference between the load in the summer and the winter is very different. That concludes my comments and Ken Silver and I are available for questions.

COMMISSIONER BYRON: Mr. Moore, a quick question if I may. Given that exemption that you mentioned that is available to you under Rule 1304, could you describe that in a little bit more detail? Is that unique for LADWP versus the other generating stations in the area?

MR. MOORE: It is a general AQMD exemption from the modeling and offset requirements for when a steam boiler is being replaced by advanced gas turbines or other advanced technology.

COMMISSIONER BYRON: So does that apply to any repowering?

MR. MOORE: It applies to any repowering.

COMMISSIONER BYRON: So here you have outlined a plan, or what your plans are in one slide. Does this mean LADWP is in the clear with regard to once-through cooling and priority reserve? All it takes is money to do the repowering and you are done?

MR. MOORE: It appears that the LADWP is in the clear with regard to the PM ERC problem, particularly now that the Judge in the LA Superior Court lawsuit has narrowed the rip and allowed the 1304 exemption to be used once again. I was not fully briefed on the once-through cooling issue before coming to this meeting, so I am not qualified to speak to that.

COMMISSIONER BYRON: Yeah, I am sure that there will be more -- you are probably not in the clear on that one. Commissioner, do you have any questions?

VICE CHAIR BOYD: Hopefully a simple question. I was just curious why the Haynes repower would go with simple cycle, even though I see there advance simple cycle versus your comment that the other plant might go through a combination combined cycle and simple cycle.

MR. MOORE: I am not sure I am the right person to address that, but I can say that the Haynes project is designed to be a quick start project, so that when the sun is not shining --

VICE CHAIR BOYD: Base load --

MR. MOORE: Right, when the sun is not shining, or the wind is not blowing, and we need to pick up load quickly, we will have those six gas turbines there ready for a quick start.

MR. SILVER: This Haynes repower is actually our second Haynes repower. We have previously done a repower with a combined cycle, so we have already made that first step.

VICE CHAIR BOYD: Yes, I painfully remember that.

COMMISSIONER BYRON: Yes, you are referring to when the projects come through the Commission, correct?

VICE CHAIR BOYD: Or do not come through -- in this case, do not come through.

COMMISSIONER BYRON: You know, Commissioner, I have received in the past a personal commitment from the General Manager of LADWP, David Nahai, that they are going to work cooperatively with the California Energy agencies on addressing the priority reserve and once-through cooling issues, and I know that he has also expressed to me the concern about the external efforts, shall we say, to exert control on local decision making capability. In general, I find a lot of folks that come to Sacramento do not necessarily like being here. But also, the grid is connected and we certainly understand that the once-through cooling issue and this issue affect you in the same way it affects the plants that operate in the ISO served control territory. So I guess I also want to add, we have also seen tremendous strides that LADWP has been making, not just verbal commitments in terms of moving towards renewables, and trying to address some of the larger policy issues that are being imposed on everyone here from Sacramento. It is extremely important that we have Los Angeles Department of Water and Power at the table. We need your input and information. I would like to thank both of you for being here today and being as forthcoming as you were, with information that is very helpful. We need to work closely with you to help solve these problems going forward. So I appreciate your being here. I do not have any additional questions for you, but -- oh, Ms. Korosec says --

MS. KOROSEC: We do have one question on the WebEx, Mr. Rising.

MR. RISING: I have a request of the previous speaker. Have you got a figure or an estimate in mind as to how many Megawatts of dispatchable generation would be needed for how many Megawatts of renewables that are being considered in the RPS?

MR. SILVER: Unfortunately, I do not have an answer for that question. That is certainly a study that we are undergoing now as we are integrating in the near future a large amount of intermittent generation, but I do not have a number at this time.

MR. RISING: Okay.

MS. KOROSEC: And I believe we also have another question in the room.

MR. NAZEMI: Good morning. I am Mohsen Nazemi. I am Deputy Executive Officer with South Coast Air Quality Management District. I will be speaking after lunch regarding the PM-10 offset issues and South Coast. I will be addressing some of the issues that were discussed with the previous speakers, but specific to the question Commissioner Byron, you asked from Mr. Silver, I would like our Principal District Counsel to clarify the response that you received, which we do not believe is correct, so if you would allow me to have Ms. Barbara Baird give an answer from our perspective, I would appreciate that.

COMMISSIONER BYRON: Certainly.

MS. BAIRD: Good morning, Commissioners. My name is Barbara Baird, District Counsel for the South Coast Air Quality Management District, and I appreciate your granting me the opportunity to talk here. This is specific to the question whether LADWP is in the clear because of the ability to use the Rule 1304 exemption, plus they have credits for those emissions that are not covered by the assumption. The difficulty is that the Court Order that Mr. Moore mentioned specifically says the District may not use Rule 1315, which is our credit generating rule, in order to use the 1304 exemption. So unless legislation that has been passed by the Legislature, but not yet signed, goes into effect, we are still in a situation where we have no credits to give, even though the injunction does not prevent us from giving them. So we do not think they are in the clear at all.

COMMISSIONER BYRON: So which legislation? AB 1318 or SB 827?

MS. BAIRD: In his case, it would be SB 827 because he is relying on a 1304 exemption, which is covered under 827. Thank you for he opportunity.

COMMISSIONER BYRON: Absolutely. Was that helpful?

MR. MOORE: That was very helpful. Thank you, Barbara.

COMMISSIONER BYRON: How many attorneys are in the room?

VICE CHAIR BOYD: There is another one.

COMMISSIONER BYRON: All right, please.

MS. LAZAROW: Good afternoon. My name is Shana Lazarow. I am an attorney with Communities for a Better Environment, and I actually want to clarify what Ms. Baird just tried to clarify, if I may.

COMMISSIONER BYRON: I remind everyone, this is not a court of law.

MS. LAZAROW: Of course, I just wanted to point out that the rule to which Ms. Baird referred, Rule 1315, has never been used by the District. So for years these 1304 exemptions have been issued for repowers and they should continue to be -- it should be continued to be used for repowers like the ones proposed by LADWP. The fact that 1315 was never legally adopted should have no impact on the implementation of that properly adopted rule. Thank you.

COMMISSIONER BYRON: I am glad Commissioner Boyd understands all this.

VICE CHAIR BOYD: I have already described this as a chess game.

COMMISSIONER BYRON: Was that helpful?

MR. MOORE: It was truly helpful.

COMMISSIONER BYRON: Are there any other questions or clarifications before we break for lunch? Gentlemen, I hope you will be with us for the rest of the day. Thank you again for being here. Ms. Korosec, may we break?

MS. KOROSEC: Yes, let's break and return at 1:15.

COMMISSIONER BYRON: 1:15. Thank you all very much.

[Off the record at 12:17 p.m.]

[Back on the record at 1:19 p.m.]

COMMISSIONER BYRON: Ms. Korosec, let's go ahead and start. I think Commissioner Boyd will join -- rejoin us soon. But I think we should go ahead and get started because we still have a lot of material.

MS. KOROSEC: That is true, we have got a lot to cover this afternoon. So we will be starting up with a presentation from Richard McCann from Aspen Environmental Group.

MR. McCANN: Good afternoon. I am Richard McCann. I am an Economist with Aspen Environmental Group. And I want to open with -- I like economists jokes and I keep a list of them, and one of my favorite jokes is about three individuals trapped on a desert island, they have been eating coconuts the whole time, and a can of beans washes up on the ocean, on the beach. It is an engineer, biologist, and an economist. And so they are trying to figure out how to get this can of beans open and the biologist says, "Well, we've got coconuts, we can smash this can open," the engineer says, "No, that's going to destroy the beans," so he says, "I can put this out in the sun, get up to super critical heat and it will explode," and the economist says, "Why are you guys making this so complicated? Let's just assume a can opener." I tell this joke because, to a certain extent, what we are doing here with this analysis is try to show where the can openers are being assumed by the various folks looking at this problem. And so we are going to walk through an analysis that shows different capacity requirements and some of the other constraints in looking at this, and try to shed a little bit more light on some of the constraints that are apparent in trying to address this problem.

So I am going to walk through first an overview of the problems and issues. I am going to go through this pretty quickly because I think everybody in the room seems to understand this better than I do in some of these areas. Now I am going to talk about the analytical approach and caveats to our analysis, and then Cory Welch, who is with Summit Blue, is going to walk through the scenarios and results. They conducted the in-depth, detailed analysis with working with David Vidaver from the Commission staff, and then we are going to talk a little bit about conclusions and further analysis, including some additional data and information that would be helpful in this process.

COMMISSIONER BYRON: And I just want to confirm, how much time do we have allocated for your presentation?

MR. McCANN: Forty-five minutes. We should be able to do that quite easily.

COMMISSIONER BYRON: All right, thank you.

MR. McCANN: Of course, the overview of the problem in this has been addressed several times, and I am going to just go through this quickly, one is addressing the issue of peak load reliability, both within SB 26 and within DWP, dealing with transmission and resource constraint conditions. The second is the push for retiring or replacing OTC units, and the third is being able to acquire enough ERCs in order to replace generation as needed, over the next period until about 2020.

The important environmental constraints that we are facing are the proposed orders by the State Water Board, the ERC issue in the South Coast, and then what we are looking at is the interaction between these two policy objectives, and then also meeting reliability in RPS goals at the statewide level. What we were doing was, first off, trying to create a tool to estimate the resource requirements for peak loads during the period out to 2018, the minimum operating requirements for replacing OTC capacity, and I am going to talk about some of the caveats of that in a moment, and then also looking at the ERCs that were created and also needed in order to replace the OTC units. I also want to say something about this tool, is that it is really a reduced form tool, that is that we took public data, and took some results from some of the analytic models out there, the very complex models, and essentially derived the important parameters from those models so that we could put them into a simpler spreadsheet type model. We started with an Excel model and then moved on to analytic, which uses the same kind of platform, and Cory can explain a little bit more about that model. And then we were able to run a number of different scenarios very -- quite quickly, and we were able to do this with this tool, we were able to look at scenarios quite often, and so that this is a very useful way of looking at this policy problem, is to be able to do this type of reduced form analysis using, in some cases, heuristics, in contrast, running very complex transmission planning models, which are useful for when you are doing your final design on your transmission system, but may not be really the appropriate tool for doing this type of policy analysis.

What we did is we looked at a number of scenarios that varied by different types of demand forecasts, and different types of retirement scenarios, and resource additions. What we were looking at is, if you stress the system in certain ways, how the environmental constraints impinge on meeting your reliability goals that you have for your system.

This is just an overview of the model that we have. This is -- on the right-hand side is the input and output sheet for the analytical model that we have. This is an exploratory model, it is not a truly predictive answer of what will happen. What we are looking at is what might happen under different types of demand and resource scenarios. It is flexible, it is focused on scenario analysis, it is a very transparent model, you can look at the assumptions very quickly by pushing the different colored buttons that are on the screen, it is easy to inspect and modify the inputs, and you vary the assumptions in a multitude of dimensions with this particular modeling platform.

One of the things that we started with was a topology of the transmission system for both the ISO and DWP, and you can see the overlap and interconnections between the different systems, and this was in some ways the framework in which we were starting from in order to try to identify the various constraints that the system faces. One of the key things that we had to do was derive what were the transmission congestion constraints on both the DWP and ISO systems, and you can see from these graphics, what we did was we started from 2007 load data in both cases, and in the case of DWP, we had actual load degeneration data from DWP and it is the light blue graphic -- the purple line that sort of squiggles around the right-hand side of that mountain is the transmission constraint for DWP, given an assumption that it imports all of its energy needs, but still needs to meet in-Basin reliability requirements. So essentially what is happening is DWP's generation is only running to meet reliability, but not economic energy requirements. And so that was our upper bound on transmission capacity for imports during different hours of the year, under various load conditions. And then, on the right-hand side is the ISO version of that graphic, again, the pink line is the upper level of transmission capacity and the yellow line is the lower bound. In the case of the ISO model, what we did was we ran the FNM model under 2007 conditions, and derived -- again, in reduced form -- the transmission capacity relative to load conditions, and generation conditions in which all generation was solely for reliability reasons, we assumed 100 percent imports to meet all economic energy requirements.

COMMISSIONER BYRON: And, excuse me, Mr. McMann -- I am sorry, Mr. McCann -- what is the vertical access on the left figure? Does it say "observations?"

MR. McCANN: Observations, right. That is the number of hours that a particular load was observed, so the highest peak is around 3,500 Megawatts of load, you can look on the right-hand access, it says load Megawatts, and so the highest number of hours at which LADWP experienced a load was at 3,500 Megawatts, or, in other words, it runs most often at about 3,500 Megawatts. But the size of the load, that peak, is not really that important to our analysis, it is a graphical way of showing how we ended up driving our results.

COMMISSIONER BYRON: But the observations we need to be concerned about are the few number that fall outside the bands that you have got?

MR. McCANN: Right. Or approximately so. What we were looking at, those are the peak import hours. And, in fact, we are being conservative by drawing that purple line inside the observations. They, in fact, have the capability of importing more Megawatts than what we have in that curve, but we were trying to be conservative in our estimate of what their import capacity was.

COMMISSIONER BYRON: Okay.

MR. McCANN: The computer is running a little slow. So what we are looking at are a couple of key relationships. The first one, we are trying to estimate the local capacity requirements, regardless of the resource conditions, which is we are estimating the peak resource requirement and looking at the maximum amount of imports via transmission, and then estimating what is the internal or in-Basin capacity requirement for both DWP and for the ISO, and we estimated those independently of each other. And then, a second relationship we are looking at is the additional capacity that is required to displace fossil fueled OTC units. We have the capability of looking at if we are going to retire San Onofre, as well, but that is not a case we looked at as being immediately relevant to the analysis that we were doing. So what we are essentially doing is trying to estimate, if you had to build a certain amount of new capacity to retire different amounts of OTC-type units, how many Megawatts would you need, given these various capacity requirements in-Basin.

Also, we are looking at the amount of ERCs that were needed under the different scenarios, and we were looking at both the ERCs that are produced when you retire an OTC unit, and we estimated those from historic data, from ARB's Emission Inventory dataset. Those ERCs probably would differ year by year because these generating units -- it is based on the amount of generation that they actually produce throughout the year, but we only had historic data to work with, we did not have scenarios of future generations that we were working with. And then we also estimated the amount of ERCs needed to permit a new generating unit, and in most cases we took those ERC amounts from requests that were in the Applications for Certification and other siting information, much of it filed here at the Commission in the siting cases.

And then we were looking at -- we did not really look at the question of how new transmission and other generation factors would affect ERC production, or demand for ERCs. In other words, we were not really looking at how the amount of generation would vary for new generation -- the amount of emissions would vary with the amount of generation from new generating units, we just took the amount that was specified as a fixed amount in the applications, and that would be another step of the analysis. For example, a power plant might be estimating that they are running at a 20 percent capacity factor because they have a large amount of economic generation sales that they expect to have during the year, and so they might make an ERC application based on a 20 percent capacity factor. Well, it might turn out that you really only need that unit to run at a 5 percent capacity factor to meet your reliability requirements, we have not done the calculation yet for what that -- the amount of ERCs will be required for that level of generation, but that is something we could look at down the road.

COMMISSIONER BYRON: I just want to make sure I understand this, Mr. McCann, so when an Applicant comes before this Commission, and need to get ERCs for what they have applied for, whether they have run up to that level or not, so I am thinking that you are probably running a case that, even though it may not be real, it may not need all those ERCs, they have to acquire all those ERCs. So I think you are running the right case.

MR. McCANN: Well, I guess the question is, it would be a question of whether they have to acquire those ERCs. That is what they project that they need probably in order to make the economics of their power plant pass muster, but that may not be the amount of ERCs that you really need to have that power plant meet the reliability requirements that you need in-Basin. Do you understand the distinction between those two?

COMMISSIONER BYRON: Yes --

MR. McCANN: And so one is a wish list of ERCs and the other is the list of what you really might need for ERCs. Now, there are some contractual issues that might be related to that, that I can talk about.

COMMISSIONER BYRON: All right, but it is more than a wish list, they are not going to get a permit to operate unless they acquire all those ERCs.

MR. McCANN: Well, they have -- in their projections, they have a certain number of hours that they are projecting to run, but they actually create that estimate of how many hours they project to run. They are not told by someone that is how many hours they have to run, they have to do their own internal analyses and say, "Oh, well, we think we'll run at about a 20 percent capacity factor because that is what we need in order to make our financing work."

COMMISSIONER BYRON: Or, in order to fulfill the obligations of the PPA.

MR. McCANN: Right. And so that is where the contractual issue comes in to play is the PPA can be modified to meet a different need than what might be in the PPA.

COMMISSIONER BYRON: Okay, but I will just try this one more time -- it does not matter what the reason is, they are not going to get a permit to operate unless they acquire all the ERCs they request.

MR. McCANN: Right, yes. That is the first part, I am just saying that they could go back and modify the PPA, and reduce the amount of ERC requirements.

VICE CHAIR BOYD: One point being that, traditionally, people ask to absolutely maximize the hours they might run, therefore they are obligated to get ERCs to cover that. And I think Mr. McCann is pointing out that, quite possibly, they do not have to ask for that many --

MR. McCANN: Exactly.

VICE CHAIR BOYD: -- and thus the Air District requirement would be reduced, etc. etc. Interesting observation.

MR. McCANN: So, with this model, as I mentioned, it is a reduced form model and there are some other simplifying assumptions that we have made in this model.

There are certain things we can add to this model as it goes along in order to do more detailed analysis, but the first thing is that it does rely on a reduced form and some heuristics, and reveal characteristics in which we have looked at model results and historic system data, and we started this from using 2007 because that was the most complete year that we have of data. It focuses solely on meeting reserve margin targets as defined in the ISO's local capacity requirement analysis, and we tried to use similar parallel assumptions for DWP. It does not include economics or ancillary services, generation beyond the reliability requirements. And it also does not include some of the -- I will talk about some of these in caveats in some other dimensions that have already been talked about today -- it relies on published resource plans, to a large extent there is some confidential data that is included in the model, but it definitely does not necessarily represent the optimal or otherwise desirable plan. It is a set of plans that basically have been published in public places, and we do not check the economics or any other type of assumptions that are in the model to see if they are optimal.

The caveats as I mentioned in using this analysis, it does not include the ancillary services requirements that include sub-area minimum generation, voltage and stability support, the inertial constraints, the ramp rate limits, and some of the other factors that have been described here. The transmission capacity is dynamically linked to load, but it is not linked to other variables such as the differences in generation levels. It is contingent on transmission and other resource plans, developing as specified by the ISO and DWP, along with some modifications made by the CEC staff input, but it does have those sorts of limits. The model does have the ability to use different resource plans if people want to come forward with different proposals. And then, in using the results, it is important to understand that these results are directional and indicative, not exact specifications of what may happen. But it is useful for assessing the feasibility of meeting different policy goals and the tradeoffs that the different agencies face in trying to make different resource planning decisions. While it shows the range of potential outcomes, you cannot really bet on the best outcome, you cannot plan on winning the lottery, you have got to look at the full range of scenarios and potential outcomes. And there are, in some cases, it will require more detailed modeling in order to address some of the caveats that I have discussed.

And then I am going to turn it over to Cory at this point and he is going to talk about different scenarios that we used, and then discuss some of the results, and then I will come back and talk about some of the conclusions and additional data needs.

MR. WELCH: Thank you, Richard. As Richard mentioned, this tool is very focused on scenario analysis, it lets us look at a number of different situations and assumptions to understand the impacts that those assumptions have on reliability constraints, ERC needs, OTC capacity, and whether or not we can displace that, and so forth. So we actually analyze about 16 different scenarios with this tool. I am going to show eight of them here, just to keep it somewhat cognitively feasible, so we can absorb it into the amount of time that we have.

We looked at two different demand scenarios, a high stress and a low stress case, and I will define on the next slide what those scenarios really are. Likewise, too, transmission scenarios, one where we completely excluded new transmission so that we can see the impact of that, and one where we assume that the transmission plans go according to schedule. And then we looked at four different supply scenarios, and I will get into exactly what those supply scenarios are in upcoming slides, although I am only going to show you two of them, but they are the more extreme bounds of the scenarios we analyzed, so the intermediate ones, we do not lose a whole lot of information by excluding those from this analysis, or, excuse me, from this presentation.

The first thing that I have to apologize for and point out is that this slide on the screen is correct and I think what you have is a print-out, there are some things in reverse, so let me just point out what those are. The bottom line is a low stress case, it uses a high assumption about renewable penetration, so, obviously, if I have high renewable penetration, that reduces the need for capacity, and likewise, if I have a high utility scale, it reduces the need for new capacity to replace our fossil fuel OTC. So these are actually reversed in the paper you have, but they are correct on the screen. The low stress case uses a 2009 draft mid-range forecast, may I emphasize the word "draft" there because my understanding is, just this last week, there is another workshop to update and finalize that, we had not incorporated that yet into our analysis. But, in general, that is a lower forecast demand than in the high stress scenario, which uses the 2007 IEPR forecast. And, again, my understanding is that the updated 2009 Forecast Demand is going to be somewhere in between those two, so, again, we sort of feel like we have bounded the problem here.

The transmission scenarios, again, I just have two. These are included or excluded. If it is excluded, that is zero; if it is included, new transmission comes online with the capacities that you see on this chart. So, in other words, in 2013 and in the LADWP control area, I see, you know, roughly a 2,200 -- I think it is 2,266 or something to that effect, coming online in 2013, and about 3,200 Megawatts of capacity in the CAISO controlled area by 2013. And, again, we have the ability, the flexibility to adjust these numbers, to adjust the timing of this transmission coming online, and magnitudes, and so forth, so that we can understand the impact of that. On the supply scenarios, it is important to note that the supply scenarios incorporate two different things, 1) the retirement of existing OTC capacity, as well as new capacity that is postulated to come online. And in some cases, there is a net zero, in other cases there is a net increase or a net decrease, depending on the actual scenario that we are looking at, and I will walk through those again on the next slide.

I am going to show a low OTC retirement scenario and a long run OTC retirement scenario, and you will see how those are defined. I know this has been an I-chart, you have got it on your paper there, and so you can refer back to that as I go through the following slides and kind of see, well, what was coming online and when, because I know this is a big difficult to absorb. But from the CAISO perspective, you can pretty much think of the low OTC retirement scenario as not really changing much, nothing really retiring, and I think only Riverside, in 96 Megawatts Riverside, coming online in January of 2011. In the long run OTC retirement scenario, we pretty much took the plans and the best estimates and some professional judgment with the assistance of the CEC staff, to come up with feasible retirement dates for these units. And in many cases, those are repowers, and in some cases those are re-powerings as in the case of El Segundo, in other cases they are new units, and in some cases we even kind of postulated our own additional capacity, which would be then replacing capacity that had retired.

For the LADWP analysis, we kind of originally came up with these scenarios, looking at both of them together, so unfortunately the low OTC retirement scenario and the long-run OTC retirement scenario do not differ a lot in the LADWP analysis; how they do differ is really in whether or not Scattergood Unit 3 is retired or repowered within the time frame of our analysis, which is 2009 to 2018. So in the low OTC retirement case, it is not retired, Scattergood Unit 3, and in the long run OTC retirement case, it is. These values, you may notice on the footnote in the previous slide, as Richard mentioned, these are based on publicly available documents. We looked at LADWP's capacity resource accounting tables, and basically plopped those dates into our analysis because that is the publicly available plan for new capacity.

So the net impact of these additions to capacity and retirements is shown on these two slides. What you will see in the CAISO controlled area is that the low OTC retirement case, we see a fairly stable capacity line there, whereas, with the long run OTC retirement, you kind of see a peak coming on, and then in 2013, that is basically where that 850 Watt Sentinel peaker coming online, and then, as we retire additional OTC capacity and add less new capacity, this scenario showing a net decrease in your total capacity in the Basin. In the LADWP situation, really, the two scenarios, as I mentioned before, are very similar. You will see a slight divergence in 2018, and that is, again, really caused just by that Scattergood Unit 3.

COMMISSIONER BYRON: So are you looking up these two cases for LADWP's control area as bounding?

MR. WELCH: I would say in LADWP, I would not necessarily call those bounding. Again, when we sort of came up with these scenarios, we had a list of plants and said, okay, what do we think are likely scenarios? What do we think are likely situations? And I guess I would say that LADWP received a little less scrutiny in looking at the bounding scenarios as then did CAISO. But I think what we will see in the following slides is that we still have some information that I believe to be revealing about what is going on in the LADWP area.

That said, if it is okay, Mr. Byron, I will jump to the next slide. This calculation, Richard showed this relationship, but let me just describe it again real quick here. It is the additional capacity that would be required to replace OTC. And when I say "additional capacity," there are some additions and retirements of OTC in our prescribed scenarios. In some cases, I think in most cases, what we have prescribed to retire and/or add for new capacity does not necessarily add enough for us to be able to just completely displace the operation of OTC units to meet our reliability requirements. And so, what I am showing here is the additional amount of capacity that we would have to add either through in-Basin generation capacity, or via increasing our transmission and ability to import. So when we look at the scenario and basically do a delta from there and say, well, we need more, or we do not need more, relative to what was described in that scenario. So in the low stress case for CAISO, what you can basically see is that, remember from our previous slide, we did not have much in the way of a retirement, and we did not have much in the way of new additions, other than Riverside at 96 Megawatts. So if that is all we do, what we are suggesting is that you still need an additional 2,000 Megawatts of capacity in the CAISO control area in order to allow you to essentially not have to run those OTC units. The other caveat is something Richard mentioned earlier, and that is this number does not include San Onofre, so this does not include displacing SONGS yet. If you wanted to include that, it would be a pretty simple addition, you would just add about 2,250 to these numbers, so you can kind of keep that in the back of your head. But I think our implicit assumption was that that was not a unit that was going to be shut down or replaced by new capacity, it is a base load unit; rather, we would assume that we would either have an exemption, or it would comply. So one or the other. So that capacity at San Onofre is excluded from these numbers. That is something important to bear in mind.

So the bottom line is, what we are saying is, yeah, there is excess reserve margin in the CAISO control area, however, there is no so much excess reserve margin that I can just retire all my OTC units. I would still need to get a couple thousand Megawatts of capacity from somewhere, today, either new units, or new transmission, in order to meet reliability in the CAISO control area -- in the low stress case. In the high stress case, with a higher demand assumption, it is even more.

The other thing I will note is out here on the far right, you will see more of this in the future slides, and there is a little blue patch here. What that blue patch is, is, again, with our scenarios, we took that as here is the prescribed capacity that we have. In some cases, that prescribed capacity that we put into the scenarios was enough to meet reliability, and in other cases it was not enough to meet reliability, regardless of whether or not OTC units are operated. So this blue line here basically says that, in 2018, the amount that we said we would add per this scenario, and retire for this scenario, did not result in enough capacity to meet the reliability requirements in what we assumed was a basic 15 percent planning reserve margin. And so there is a blue patch there that says, well, not only would I need more capacity to displace OTC, I would need even a bit more, yet, relative to what I prescribed in that scenario to meet the reliability requirements. That is important because you will see that blue show up quite a bit more in future slides.

What I have tried to do on the screen here is kind of show in color what is changing on the scenarios. We have a lot of scenarios we are looking at here, so what I am doing in going from this slide to the next slide, is I am only changing the assumption about what happens with transmission. It is still the low OTC retirement scenario, it is still the CAISO control area, but I am now going to say what if we then include all that new transmission that is in the plant? So when we do that, what you see is that, in the low stress case, so if I make an assumption that I do not have a big demand growth and that I have got a lot of renewables coming in, you see the transmission gets us pretty much out of the woods, at least as far as replacing fossil fueled OTC capacity in the 2013 timeframe, in the low stress assumption. But, again, we cannot necessarily plan on winning the lottery, as Richard pointed out, and so we have to look at the high stress case, as well. And in the high stress cases, it says, no, you did not quite get there. You did not quite make it out of the woods just as a result of that new capacity coming online. So that is really what I want you to get out of this slide.

The next slide, I have kind of jumped, then, to changing the OTC retirement scenario, and now I have gone to the long run OTC retirement scenario, and I have then gone back to excluding new transmission. So the long run OTC retirement, as you will recall, had quite a few retirements and quite a bit of new capacity coming online. And, in fact, the net reduction in total capacity that is in-Basin. And, again, what we see in this situation is, if I replace all that capacity, repowerings and retirements with new units coming online, and so forth, again, I am out of the woods in the 2013 timeframe in the low stress case, but I am not out of the woods in the high stress case. And, again, when I say "out of the woods," I am talking about only from a reliability and OTC operation perspective, not from an ERC perspective. ERC is later, and we will see those on future slides. I am not necessarily out of the woods on being able to acquire enough ERCs to put this capacity online.

So the next thing that I will change here is, again, jumping from excluding new transmission to including new transmission. So now what we see is, if I both retire quite a bit, I repower quite a bit, bring a lot of new units online, and allow that entire 3,200 -- assume that entire 3,200 Megawatts of new capacity comes online, then in both our low stress and a high stress case, I am out of the woods from a requirement to operate those OTC units to meet reliability.

So the next -- we will basically walk through those same scenarios, same combination of scenarios, but for the LADWP control area, and what we will see is the situation is quite a bit different, or somewhat different in the LADWP control area. The first thing that we will note is that, at least by our analysis, again, with the publicly available data that we have, and using our analysis of transmission constraints and transmission congestion, our analysis indicates even today they do not necessarily have a 15 percent planning reserve margin, and given that they have about, you know, almost 1,900 Megawatts of OTC, what you can take away from that is that, if I retire any OTC unit in the

LADWP control area, today, our analysis would suggest it has got to be replaced with something else. There is no extra in the LADWP control area, it is already tight. We do not have the benefit of the CAISO control area, which is up in the 27-28 percent reserve margin today, and then therefore, you know, some of that does not have to operate today. But they do not have that luxury, at least by our analysis, in the LADWP control area. So again, without any new transmission and with what we prescribed in the low OTC retirement scenario, they are not out of the woods in the entire timeframe that we have described.

Now, if I include new transmission, that is a different situation. The transmission plan, what we are looking at, is almost 2,400 Megawatts of new transmission coming in 2013, and basically that says that is enough to get you there. And if I jump back to that previous slide, you can sort of see why. If I look at this, I can see, well, gee, you are telling me I need about 2,000 and, in the highest case, maybe 2,100 in 2018 in the high stress case, but then I am going to add 2,400 Megawatts, right? So that should go away, and it does. So it kind of passes the dummy test there if we add that much capacity in transmission, you would be out of the woods from an OTC perspective and a reliability perspective in the LADWP control area.

Then the next two scenarios are actually very similar, as you might imagine, because as I described earlier, the long run OTC retirement does not deviate significantly from the low OTC retirement scenario, so really the only difference we see is out here in 2018, where this is a little bit lower in 2018, but basically the same takeaways for the long run OTC retirement scenario, both including and excluding transmission as I have just described for these low OTC retirement scenarios, same conclusions there.

So again, that is getting us out of the woods on reliability and OTC capacity, but not from an ERC perspective. Just to summarize all those eight -- well, actually, 16 charts that you just saw, so, again, I appreciate that a lot of data, a lot of information being presented here, I tried to summarize that a little bit in just a table, and what we basically see is, if it is green, I have gotten out of the woods some time between now and 2018, and if it is red, I have not, and, again, only from an OTC capacity and reliability perspective, but not necessarily from an ERC perspective.

COMMISSIONER BYRON: If I may? Green is good.

MR. WELCH: Green is good.

COMMISSIONER BYRON: Doesn't this also imply, then, that if you are building transmission, you are also addressing the ERC issue?

MR. WELCH: Yes, and we will see on the next couple of slides that, whether I include or exclude transmission, that does have an effect on whether our ability to get out of the woods from an ERC perspective, certainly, if I add all that capacity with just transmission, then I am much better, obviously, from an ERC compliance perspective, rather than trying to add new generation. I mean, in an ideal world, we just add all the transmission we need, and then we would not have an OTC problem or en ERC problem, but right now it is indicating that, at least per the units and transmission plans, that does not always get us there. In some cases, it might. So I think it will be addressed on the next slide or two, if it is not, perhaps we can come back to that, or we can address it offline.

So the bottom line is, in the CAISO control area, I am really only in the green, and if I have that new transmission assumed, and in the low stress scenario I am good in both the retirement cases, but in the high stress scenario, I am not good with the low amount of retirements, I need to retire something. In the LADWP case, we are basically saying, hey, you are out of the woods if you include a lot of new transmission, regardless of what we assumed on high stress, or low stress, or low OTC retirement, or a longer OTC retirement.

So the next couple of slides then get into the ERC's generator requirements. You have got about 10 minutes left, so I will get through these pretty quickly. Richard already described and you discussed what these values are, it is really -- we estimated the amount of ERC's that would be generated by retirement of OTC units, and then just used the amount that was requested in applications and so forth. What you can really just take away from this slide is that, really, on all of these slides, there is a net increase, really. The blue line is above the red line. So the amount that is being requested for ERCs in all these scenarios exceeds the amount we would expect would be generated by retirement of OTC units, and so therein we have got a problem because, in this case, there is a Delta of several thousand almost pounds per day, and I think I read somewhere in another presentation that there was maybe a grand total of a thousand on the market. So you cannot really get there from here. So we still have that as a problem.

And in the next slide, same situation for the LADWP control area. The net requests for that new capacity exceed the amount that you would expect to be generated. In this case, the red line is not very interesting, and that is because this red line is, again, based on the requests, and the requests that were provided for Haynes and Scattergood in the LADWP control area were net. In other words, they applied or assumed that that 1304 exemption where you can just look at the net Megawatt change, they assumed that would be the case, they would not have to add that 900 pounds per day that was shown on an earlier slide, it would net out to zero for Haynes and Scattergood, and so that is why the red line is zero there, because they are essentially requesting nothing. They are saying it is out, we are good, or a negligible small amount that does not show up on this graph. So, really, in the case, for instance, of Haynes or Scattergood, any amount that is new would show up in the blue line, but that is pretty much negligible for those two plants.

That being said, I will kind of let Richard jump back to conclusions, unless there are any questions on any of those slides I just presented.

MR. McCANN: Thank you, Cory. Just two last slides here. The first one is just talking about our conclusions. As Cory pointed out, we are finding the DWP is in a capacity short situation, regardless of what we are doing with OTC policy, so they are much more constrained than the ISO area is in terms of dealing with this issue. The other one is that, as new transmission lines come online, the ISO may have to specifically designate what type of power plants are running, and the reason why I bring this up is because of the inertial constraints and the ramping requirements that have been talked about earlier. What has happened up to this point is that those requirements have been masked by the capacity requirements that have to be met in-Basin, and the new transmission lines relieve that constraint. So, now, new constraints arise and we are going to have to be much more specific about how we address those new constraints in the planning process. They have not been identified so clearly in the past as they need to be in the future. What the interesting thing is, that as we add transmission, it does appear to allow the retirement of OTC units, but again, it is contingent on meeting these various other operational requirements for which we would appreciate getting more information on those. And then, finally, there is going to have to be ways of dealing with acquiring ERCs beyond just retiring OTC units, there is going to have to be other sources of ERCs for meeting in-Basin generation requirements, regardless of the scenario that we are looking at.

And I just want to conclude with the additional data that we would desire to enhance this analysis. First is, specific operational nomograms like the SCIT, having numeric values, not graphs, from which you cannot really derive values, and other types of operational constraints like the blacked out graph that David put up of Orange County operational constraints, that sort of information is necessary for doing further analysis. And that has to deal with minimum generation requirements and next-day commitment issues that affect OTC units. All these OTC units, basically they run 24 hours a day largely because they have to commit for running the next day to meet the loads, but that minimum generation has actually been used to meet other types of requirements and, as I mentioned, that capacity requirement has been masking that up to recently.

And then we also need more specific information on expected ERC generation and needed requirements at the unit level because most of the data is at the plant level. And I think that was about it for our list. I appreciate all the support we have gotten from the CEC staff on this, and appreciate being able to present this to you today. And we are open for questions.

COMMISSIONER BYRON: Very good. I suppose, given enough information, we can model anything. What we have asked you to do here is extremely complex and you have covered most -- many of the variables. And I think you mentioned this in the last couple of slides to some extent, but you know, these additional complexities -- ramping, inertia, stability -- if I was to look at your results, it seems to me I would tend towards the transmission solution, but when I have to consider these other things that you cannot model, at least at this point you are not able to model, don't those emissions really decrease the value of the results of this work? Because, I mean, what we have heard earlier this morning is transmission comes in from the north, we need generation from the South to meet those load areas. You know, that kind of stuff, these ancillary services, doesn't that really devalue the results that we are getting here?

MR. McCANN: Well, what we started with in this analysis is that there was a belief that there was capacity requirements, in-Basin, that were needed, and that is what was keeping these plants online.

COMMISSIONER BYRON: Right.

MR. McCANN: And what we found in this analysis is that it is not the capacity that is doing that, so what we have done is we have been able to move beyond one layer of that type of analysis and say, okay, if we can solve the transmission problem, and that is a big "if" because, for example, DWP just announced that they are having second thoughts about the Green Path project, which is one of the big components that is in this analysis. So that sort of thing is important in terms of incorporating in our scenario analysis. But once you have that information, once you have those kinds of scenarios, yes, you probably can solve this with transmission, but transmission is not always an easy answer. And then we can move on to these other answers.

Now, the thing, for example, the inertial requirements, it is probably likely that we can get values that we can use in this model, and quite easily, with some discussions with the ISO and DWP about the inertial values in these individual units. And actually getting the underlined data for the SCIT, that sort of information, we could probably incorporate into this model and move on to another layer of analysis -- actually, quite easily. To be honest, we would not have to wait six months for an answer -- to answer that question sufficiently, to be able to move on to some other policy questions.

COMMISSIONER BYRON: Good. Well, I will look to staff to evaluate whether or not that is indeed the case, because we are looking for all the information and analytical tools we can get. Commissioner, before I open it up to others, do you have any questions?

VICE CHAIR BOYD: Actually, no. Mine have been answered. I am impressed, if not overwhelmed, but this information, it is very very useful and interesting, so thank you.

COMMISSIONER BYRON: Yes, sir, please identify yourself.

MR. KOSTRZEWA: Thank you. My name is Larry Kostrzewa. I am from Edison Mission Energy. Just following up on what Commissioner Byron was asking, it sort of looks to me that, by ignoring ancillary services, and inertia, and ramping requirements, your analysis basically says, "If we repealed the laws of physics, this is how the numbers would work out," and you just need more data to factor in the laws of physics. Is that correct?

MR. McCANN: No, well, yes, we do need to factor in the laws of physics, but as I mentioned, really what this analysis was, again, it is about the fact that there was an initial premise that it was the in-Basin capacity requirements, the need to meet the peak load Megawatts, which was driving the requirement for OTC units. What our analysis shows is that is not necessarily the case, that it is this next layer of issues, of which these are arising, but if those can be revealed transparently, that we can address those issues further in the analysis. And one of the things that we found in this reduced form analysis, one of the things we found, for example, with the transmission capacity, is we were able to model the ISO and DWP transmission imports by looking at a reduced form model. We did not have to run the full blown transmission models in order to get the answers that we got. We were able to derive the important parameters and, by being able to derive those important parameters, you are able to get to answers that are reasonably approximately, reasonably close, in order to do policy analysis. I would not be doing transmission planning or to add generation units based on this analysis, but you can address the question of what kind of constraints are you really facing, and which constraints do you need to relieve.

MR. KOSTRZEWA: But, in fact, it is the laws of physics that prevent transmission from solving the problems that you are saying transmission can solve.

MR. McCANN: Right, and so what we -- part of that is, is people assert that, and it would be useful to get the numbers so that we can look at that.

MR. KOSTRZEWA: I had one other question. Looking at your slide 16, you show about 3,000 Megawatts, a little over 3,000 Megawatts of transmission being added in the CAISO area in 2013. I assume that most of that is the Tehachapi project?

MR. McCANN: I would have to look. One of the things is that the ISO did not provide us an individual breakdown of units, so there is actually three large transmission projects that have all come online, and we do not know what the breakdown is between the individual --

MR. KOSTRZEWA: Well, I believe that most of that would be the Tehachapi project, and so it also matters what is on the other end of the transmission line --

MR. McCANN: Right --

MR. KOSTRZEWA: And at the end of the Tehachapi

Transmission project is wind generation, which counts for the net qualifying capacity for wind is about 9 percent of the nameplate, so 3,000 Megawatts of transmission capacity really only provides about 270 Megawatts of load carrying capacity.

MR. McCANN: That was already addressed actually. What we did is we took the ISO in its LCR tables for 2013 produced -- estimated the amount of local capacity requirement that was needed in-Basin with the addition of transmission projects, and --

MR. KOSTRZEWA: But I think you are missing --

MR. McCANN: -- excuse me, what you can do is you can derive the amount of firm transmission capacity that the ISO is assuming is available to meet peak load requirements under 1 and 10 peak demand conditions, in each specific year. So this 2013 number is a number that the ISO derived itself for the amount of transmission capacity that is available to meet peak and load conditions. And if you have a problem with the 3,000 Megawatts, I would talk to the ISO about that.

MR. KOSTRZEWA: It is indeed Megawatts of transmission capacity, but on slides 21 and 22, that 3,000 Megawatts of transmission capacity reduces the need for in-Basin capacity by 3,000 Megawatts, so you are effectively assuming almost 1 for 1.

MR. McCANN: The ISO is assuming 1 for 1.

MR. KOSTRZEWA: I do not think so.

MR. McCANN: Yes, it is. It is from their LCR table. Look in the LCR study, 2015 to 2013 LCR Study, and that is what the number is that they produced.

MR. KOSTRZEWA: Okay, thank you.

COMMISSIONER BYRON: Thank you.

MR. VAWTER: Hi, I am Don Vawter, I am with AES Southland. We own and operate 4,300 Megawatts of once-through cooling in the South Coast. Under your supply scenarios, you have El Segundo, Alamitos, and Huntington Beach repowering to some degree. And I was wondering if you were taking into account that those particular repowers would be exempt from ERC requirements under Rule 1304?

MR. McCANN: We were using the net numbers and I believe, Cory --

MR. WELCH: I know that to be the case for El Segundo, yes, it is the net numbers. I cannot speak off hand for the Alamitos situation, it may have been the plant by plant analysis where we received the net created, or the amount created from retirements, and the amount needed for new units. I do not know if that is the case for Alamitos, but I know that it is for El Segundo. We can look at that.

MR. VAWTER: Yeah, I think it would be interesting if you took a look at different repowering scenarios of OTC units that were then exempt from the ERC requirements under 1304, and then see where your ERC requirement is at that point. Thank you.

MR. McCANN: In most cases, we were using the net analysis, so we were looking at that repowering question from the net perspective in most cases.

MS. UNGER: Hi, Samantha Unger with Evolution Markets. We are an energy and environmental commodities brokerage firm. And my questions are actually related to the ERC slides. I am just wondering, because this is always a very touchy point when talking about ERCs generated from shutdown of facilities, or closure of plants, and in your numbers here in your model, I am wondering if this is really ERCs or, emission reductions, meaning not the actual number of credits generated, but the amount of emissions reduced.

MR. WELCH: Okay, it is our best estimation of actual ERCs and not just emissions, so we actually do look at the historical emissions of the unit, and there are certain multipliers that you apply, of course, depending on whether or not they operated less than 30 days, between 30 and 180, between 180 and 365, so we use those multipliers to give our best estimate of actual ERCs generated, and not just emissions.

MS. UNGER: So you assume a BACT scenario here about Available Control Technology scenario?

MR. WELCH: Yes.
MS. UNGER: Based on today's technology?
MR. WELCH: That is my understanding --
MR. McCANN: Right.
MS. UNGER: Thank you.
MR. MICSA: Catlin Micsa, ISO. I would like to make a clarification. I think the information that the ISO has provided in our long term LCR results may have been a little bit misleading. Just by taking the total numbers from the overall requirements, it can give you a false sense of security, and what I am trying to say here is, yes, the requirements are decreasing a lot, staring in 2003 after we get a transmission problem, but what is happening is, actually, the pool of the units that are needed decreases a lot, as well, because we talked a little bit before that, right now, the binding problem is the entire LA Basin, it is basically south of Lugo, which has all the units in western and eastern help relieve that constraint. Once you build the transmission, almost the entire need shifts to the western area, so there is a much smaller pool of units than you can run from. So even though the requirement drops a lot for LA Basin, you can use the same amount of generation that you had before, and that table is misleading because -- our fault -- it does include all the units in the existing LA Basin, we did not went in and told people how much are in

the west and how much are in the east by totals, and maybe that was a little bit misleading and they use the total number and, once you get to 2003 and beyond, you just might want to concentrate only on the western problems and just forget about the LA Basin. And that will give you a different result.

One other point I would like to make here is that, let's say we relieve the local constraints, that does not mean that the units are not needed. We could find ourselves in a position where we can relieve the local constraints and the units now -- the binding problem becomes the Southern California import transmission. Basically, the inertia we talked before, the ramping, that the requirement for the units might move from being needed from a local perspective to being needed for the entire Southern California. And, you know, the gentlemen talk about masking the problem -- right now, so much is needed to meet local requirements, once we dispatch the units to meet that, most of the time you need Southern California import transmission, but if you start relieving the local constraints, you could end up in a situation where, yeah, it is not really needed from that local constraint anymore, but now you have a different constraint, which is Southern California import transmission. So just those two clarifications.

MR. McCANN: Yeah, and your presentation this morning was informative about the west versus east because we were aware of it, but we did not have the data in order to address that, and so we did the model the way we did. But we appreciate that there is that important distinction. One issue about once you move to an SB 26 load serving area, you can now put generation outside of the South Coast, whereas if it has to be inside the LA Basin, it has to be in the South Coast. So that is an important thing to recognize in terms of policy options that you have.

COMMISSIONER BYRON: Please.

MR. TURNER: Hi, Mark Turner with Competitive Power Ventures. One more thing that I think is important to mention is that we are still looking at this a little piecemeal. Four days ago, I was in a meeting with Yakout Mansour with CAISO, and in that meeting, we were talking about the challenges of meeting the renewable portfolio standards in our greenhouse gas goals, and one of the things that was emphasized by Yakout is what we really need in order to go beyond the 20 percent goal and towards the 33 percent goal, is this need for ramping capacity, ramping capability of units. And that is exactly the type of ancillary service that the new peaking facilities that are now under contract with SoCal Edison provide. And when you do an analysis like this and you are focused on OTC and transmission, and you leave out ancillary services, it is --

it is the can opener. It is missing. The can opener is gone, you know, I can be able to open the can and what the answer is. Yakout, you know, his emphasis was on ramping. Today we have had another individual from the CAISO talking about inertia capability and comparing that to, you know, the need for peakers. But the reality is, you know, a unit that provides excellent ramping flexibility and capability, by definition does not provide good inertial capability. So we need to fit all these pieces together, and I think if we just take what we have heard today in this meeting, we might walk away with a misinterpretation that, gee, we might not need these peaking units. But, you know, the analysis is not complete if you take in account the need of the ancillary services that are also very important for the system.

COMMISSIONER BYRON: Good. Those are all very good questions. You know, I have certainly never done a model or seeing a model, regardless of how good it was, that did not need more refinement or better assumptions, and so that is what I take away from many of the questions. There were questions asked that I would not even think of in terms of other refinements, other things we can do, but we are really going to look to staff for a determination of the value going further with this kind of work. I think it is informative, it does help us understand certain things, as you indicated, but it is not just whether or not we can refine the model, can we get better input? Can we get better information? And for that, we need to rely upon the parties, as well. So I thank you very much. Commissioner, do you have any questions for these gentlemen?

VICE CHAIR BOYD: No, just a comment, Commissioner Byron. You are very wise for your youth, I notice, in that last comment.

COMMISSIONER BYRON: Why, thank you, Commissioner. Thank you, gentlemen.

MR. McCANN: Thank you.

COMMISSIONER BYRON: I think we will press on, then, because we are a little bit behind schedule. This is really excellent material. I think next is Mr. Nazemi from the South Coast Air Quality Management District, and we appreciate your being here. I suspect this presentation you have given many times before, if not to this Commission, certainly to many other bodies. Would I be correct in that assumption?

MR. NAZEMI: Good afternoon, Commissioner Byron. You are correct that I have been giving many presentations, and each one is a little different than the one I gave before because of the dynamic situation that we are in, in this case related to offsets.

COMMISSIONER BYRON: Right. Well, we look forward to your candor, despite the fact that you brought your District Counsel with you here, as well, which maybe, I hope does not limit anything that you are able to say.

MR. NAZEMI: If it does, he will throw something at me.

VICE CHAIR BOYD: Mohsen, I thought you changed it all because the moving target is harder to pin down. Good to see you.

MR. NAZEMI: Thank you. Again, thanks for inviting me to speak at this workshop. I will try to give you a short presentation, and then I will be happy to answer any questions that you might have, either right now, or during the panel discussion. I think we all know why we are here, because we are looking at a requirement under federal, state, and local AQMD rules that, whenever there is a new or modified power plant that is proposed, that the offsets requirements needs to be evaluated. And under our local rules we have created over the last couple of decades, some exemptions from offsets for various reasons, some under Rule 1309.1, referred to as Priority Reserve Rule, particularly those where the kinds of projects that was felt were considered as essential public service projects -- police, hospital, school, sewage treatment plant, and so on and so forth -- with one exception that, in the early 2000-2001 energy crisis, we also allowed power plants to be considered, with one big exception, that they had to pay for those offsets, unlike the others who got a fee, and the fees that were collected were reinvested in the emission reduction projects.

The other exemption we have under our rules is referred to as Rule 1304, you have heard about it a number of times today, and these are exemptions that, particularly for power plants, only apply if it is being repowered, one unit is replaced by another unit, or they are very small power plants. However, even though we have these exemptions in our rules, that does not relieve the requirements under federal, state law for the offsets requirements, and therefore our district has been providing the necessary offsets for these projects through what we call an internal offset bank, where we, the district, makes it whole by providing such offsets, even though the project proponents were not required to provide the offsets.

The status of power generation in South Coast, and I am not the expert in how much capacity is in the state, but if you look at the population of South Coast AQMD, you have over 16 million, almost half of the state population is in South Coast, and I think you can almost prorate the power generation to that. There is about half of generation capacity in South Coast, as well. For the existing units that are operating, almost half of that, actually a little bit more than half of generation capacity, is actually 40 years or older, and I do not want to put anybody on the spot, but in our assumptions, usually we assume an industrial facility operates for 30 years. Once it goes over 40 years, I mean, there are all kinds of issues relative to reliability, maintenance, and availability of the systems. In addition to that, you have heard about the State Water Resources requirements for once-through cooling, and when you look at the total generation capacity, again, one-third of the generation capacity is once-through cooling plants. So what we learned in the early California energy crisis in 2000-2001 was that there was concern that, for over a decade, you know, nobody had invested in new generation because the market was being changed and deregulated, and they were not sure what they were going to get for their money and investments, so once we hit the rolling blackouts and there was clear indication that there was a need for new generation, we did similar type of amendment to our rules, and we actually permitted, and today there are more than 5,000 Megawatts of clean air and state-of-the-art efficient units that were put in place since that time. However, at the same time, we noticed that over 3,000 Megawatts of older, dirtier, and less efficient generation was retired. And the net effect was a better deal for the environment, even though we built more power plants, the power plants that were built were cleaner and less polluting.

In 2006 and 2007, the District embarked on two actions that, even though they were done simultaneously, they really were totally independent. In '05, we were getting some analysis and estimates, projections from state agencies, the CEC, the ISO, that there was need for a new generation for three reasons, projected, demand, and growth, aged units, there were studies done about, again, the age of power plants in South Coast and other parts of the state, and the once-through cooling replacement that pretty much results in either repowering, replacement, or retirement of units. So we utilized that experience that we had from the early 2000 energy crisis, we did not want to go through that again and have diesel back-up generators run, or have power cut through essential services, and offered to amend the rules to allow power plants be built to meet the state and particular Southern California demand. So we allowed limited access for newer, cleaner, and more efficient power plants. We actually went beyond BACT, requiring new power plants to meet more stringent, both criteria and pollutant toxics emission limits, and requiring them again to pay greater emission mitigation fees that could be invested in the local areas where these power plants are going to be built. But at the same time, we were in discussions with

EPA, the district again to demonstrate that the projects that are exempt from offsets under our rules still meet the federal requirements. We were utilizing a tracking system that you have heard today from others refer to as the "old tracking system," or "previous tracking system," where we demonstrated that there was adequate amount of credits available to offset those emission increases, and therefore, even though our rule exempted it, they met the other requirements under federal/state law. And as a result of our discussions with EPA, they raised a number of issues about the tracking system and credits that were of concern to EPA. So in 2006 and following in 2007, we actually revised and updated our tracking system, and worked with EPA to replace some of the credits in our system that have been used in the past with other types of credits that EPA felt they were approvable under federal law, and therefore they were legal to be used.

Now, subsequent to that action, in both years, '06 and '07, we were sued by a group of environmental organizations and, in July of 2008 and subsequently November of 2008, there was a state court decision that basically invalidated the amendments to Rule 1309.1 and the adoption of Rule 1315. And in that same order, it provided an injunction from using Rules 1304 and 1309.1 going forward. So as a result of that state court decision, the AQMD is not able to issue any permits and use our internal offset tracking system to cover the emission credits for repowering and replacement of power plants. And I think this morning you had a little bit of a debate, which I know you do not like to have in this workshop, relative to whether or not the September 9th court decision actually allowed us to go back and use those old tracking system, and I think other than the discussion between the two counsels here, our counsel and the opposing counsel, I also want to point out that the Judge's Order just put a stay on the injunction, and it did not modify the Order. So when the state expires, we are back in the same boat. But most importantly, we cannot rely on the old tracking system because EPA had raised issues relative to the credits that were used and the tracking system that was used before, and that is the whole reason why we revised it, and updated it, and they also wanted us to adopt it into a regulation to memorialize it, and we did that. But I am a little bit disappointed that I hear the plaintiffs argue that not only you can use the old tracking system, and that is what the court ordered you to do, where they themselves have sued us in federal court about the validity of credits in the old tracking system.

So as a result of this court decision, we believe that the only way that power plants can use -- to obtain permits from the district at this point is the use of ERCs that are available in the open market. The problem with that is that, 1) there is not enough in the open market, and 2) that their prices are such that they are potentially unaffordable. If you look at just the history of what the ERCs availability and prices are for PM-10 in South Coast, you can see the white bar starting from the left, going to the right, shows the availability of those credits, and between 2000 and 2009, the availability have dropped by almost one-half. And what is left actually, it shows about 1,000 pounds per day, but in reality not all 1,000 pounds per day is in the market for sale. There are companies that do not fall under any one of these exemptions under 1304 or 1309.1, and if they need to expand, they have to buy ERCs, so they have those ERCs to use for their own projects. In addition to that, you will see the price of the ERCs between 2000 and 2009 has increased by 700 times. That is close to 700 or 70,000 percent -- not 700 percent, not 70 percent -- 70,000 percent. As a result, I think the notice for this workshop was citing that the prices of ERCs in South Coast has reached as high as $135,000 or $150,000 per pound, per pay. Actually, the last price of ERCs that the transactions took place were three government agencies, the City of Los Angeles, the City of Ontario, and the City of Anaheim, that they bought PM-10 ERCs at prices ranging somewhere between $310,000 to $350,000 per pound, per day.

So if you just took the three projects that you heard this morning from Edison and some of the project proponents that they have obtained contracts from, Edison approved by PUC, the amount of credits that they need is twice as much of ERCs that is out in the open market. Now, when that presentation -- Mr. Minick gave his presentation and subsequently I think Mr. McCann from Aspen made his presentation, they argued that, "Well, maybe we really don't need that much ERCs, you need maybe only 600 pounds per day, or 700 pounds per day, or whatever number of pounds per day." I want to make it clear that we would not require more ERCs than what the applicant asks us to be able to operate, so Commissioner, you are absolutely correct that, if they ask us that they only wanted 800 pounds per day ERCs, that is what we would require. The problem is that some of the members who are going to talk this afternoon, or have already talked, are assuming that we are going to change our rules and New Source Review requirements to, in effect, change how ERCs are to be calculated. And I want to point out that there is state law, referred to as SB 288, that will potentially raise issues every time we go to change our New Source Review rule, it needs to go through a hearing through the Air Resources Board, and submittal to EPA with SIP approval, and those are not as easy as they sound, like just go out and change your rule. First of all, it has to be a change in our rules, and second of all, we think there are issues related to state law that need to be addressed there.

And then, secondly, I want to also comment on Mr. Vidaver's presentation earlier this morning where he showed a list of three projects that have obtained contracts with Edison, and then the list of projects that I believe in the slide were referred to as plants waiting without contract. And I noticed in that list, there were two projects listed, City of Vernon, and AES High Grove, and I know that there is a scheduled hearing for the City of Vernon on October 19th, so I -- and there is a chance that it may not happen, but I want to make it absolutely clear that our agency has denied permits for both of those projects. As of today, the counsel for the City of Vernon, who has appealed the denial of the permit, has declared to the Hearing Board that they are withdrawing their application for the appeal. So with that announcement, I want to make it clear to the Energy Commission and others here that we have no applications on file for these two projects, so I am not sure when you say they are waiting -- what are they waiting for? Because one of the primary determinations relative to most power plants is air quality determination, and our determination of compliance is that there is no application to determine any compliance.

VICE CHAIR BOYD: Mohsen, just for your information, I was reluctant to say anything as the Presiding Siting Commissioner on South East Regional/Vernon, that we are aware -- we have been informed by their counsel, you may want to verify this later, but they intend to withdraw their application. But that is late breaking news, frankly.

COMMISSIONER BYRON: And the other one you mentioned, was it -- did I hear you correctly -- High Grove?

MR. NAZEMI: AES High Grove. We denied their permit and they did not even appeal our denial.

COMMISSIONER BYRON: All right, thank you.

MR. NAZEMI: So, aside from these other power plants that we are all here to talk about, I wanted to point out that our inability to issue permits under 1304 and 1309.1 affects other projects that are, to me, power plants. And these are renewable projects. I just listed three of them here on landfills in Irvine, Brea, and Sylmar that, together, they add up to about 75 Megawatts of renewable generation. Last week, we received an application for a 500 Megawatt solar power plant called Solar Millenium Plant, to be located 10 miles east of Desert Center in our jurisdiction. This plant actually requires, and I have since -- I prepared a slide, it has been recalculated -- this plant requires about 11 or 12 pounds of PM-10 ERCs, so if you look at these other projects, they cannot go forward unless they supply their own ERCs also, and it will cost anywhere from $6 to 100 million to get those ERCs. So I think the focus of the Energy Commission right now is the projects that are in front of them, but there are other projects that are going to help the grid, but they are not going forward.

So, Commissioners, I think today's workshop -- and I really thank you for holding this workshop -- is a very good example why our agency has decided not to amend 1309.1 for power plants anymore. We believe that this task is the state agencies' who have expertise in energy planning, transmission lines, generation, and demand forecasts. We tried to help the Southern California region when we were told that there is a crisis coming, but I think it reminds me of an old cartoon in the newspaper where the global warming was not as prevalent as it is today, where they were holding a seminar on global warming, and there were people sitting in Eskimo suits on one end of the table, all the way to in their swimsuits at the other end of the table, and these were all the expert panels. So I think your -- I do not envy your job, but there is a need for the experts to get together and put their heads together and, as Commissioner Byron, you stated, be open and share information so everybody can understand what assumptions were used to drive conclusions. And it is really important to do that.

So what are we doing, though? We are continuing to proceed with the re-adoption of Rule 1315. We are expecting that some time in the first quarter of next year, we will be able to do that, but what is important at this point is there is proposed legislation that has passed through both Assembly and Senate, awaiting the Governor's signature under Senate Bill 827, that if signed into law will allow us to use the old tracking system, which everybody says is good to use, but have enough credits in it, not just use the old system, but have enough credits in it to be able to stand behind the permits that we issue. Without that, as of today, the permit moratorium is still in effect, so I wanted to make it clear to folks from LADWP that we are not ready to issue their permit for Haynes because we do not believe that we can do that without having adequate credits in the market.

COMMISSIONER BYRON: So you just mentioned the one piece of legislation on your slide. Are you endorsing both? Or either of these, I should say? Or just the Wright Bill?

MR. NAZEMI: Commissioner, I believe you are referring to Perez Assembly Bill 1318. That is specific to one single power plant and I think we are really asking -- not asking, but we are supporting SB 827 because we need a global solution to permit moratorium.

My last two slides are really a response to the comments or questions that were part of the notice for this workshop, and that is what else we need to worry about. I think we all know that there is a new national MN quality standard for the fine particulates which is smaller than PM-10, referred to as PM-2.5, this standard was adopted in 2006 by EPA, and as of this date, the final rule was issued in May, and it has a three-year sunset -- not sunset, but implementation deadline. So the effective date of the rule was July of 2008, and we have until July of 2011 to implement a PM-2.5 into our new source review program and into the State Implementation Plan. However, having said that, South Coast is one of the only two areas of non-attainment for PM-2.5 under new federal standard. The other portion of the South Coast Salton Sea and Mojave Desert Air Basins are attainment, but South Coast Air Basin, which is the majority of projects we are talking about here, is non-attainment. And under the EPA PM-2.5 rule, we are required to use what is referred to as Appendix S, which is kind of like EPA's non-attainment New Source Review Rule, to use that Appendix S in the mean time, until we implement it into the SIP for permitting of any PM-2.5 source. And the way the source is defined under the federal law is any facility that has potential to emit 100 times per year or more of PM-

2.5. So if any of these power plants, existing or new, that are undergoing permitting, if they are a major source of PM-2.5, then we would have to address that, and one of the requirements under the Appendix S for PM-2.5 is requirements for offsets.

And the last item that I wanted to point to is the greenhouse gas global warming requirements that, under the Federal EPA endangerment finding that was issued in April of this year, they identified six greenhouse gases, including carbon dioxide, as contributing to air pollution that may endanger public health or welfare, there is the federal Waxman-Markey Bill that, under Title 1, has requirements for renewable combined efficiency standards, and there is the state, of course, AB 32 Scoping Plan requirements for the renewable 33 percent and cap-and-trade that would begin with electricity generation in large facilities in 2012. That pretty much concludes my presentation, but I would like to ask Oscar Abarca, our Deputy Executive Officer for Public Affairs, to also make a conclusory statement.

MR. ABARCA: I just want to clarify a statement that Mohsen made to answer your question, Commissioner, and that is that, with respect to the AQMD's position on SB 827 and AB 1318, our agency, the South Coast Air Quality Management District, is the sponsor of SB 827, and we support AB 1318 because it has the correct language that would allow us to access credits from our bank, to be able to issue to that one power plant. Thank you.

COMMISSIONER BYRON: Thank you. Commissioner?

VICE CHAIR BOYD: Just a quick comment. Mohsen, good to see you. I appreciate your kind words about the need for and the capabilities of the energy agencies to deal with this issue, but I suspect that, if not you, your boss delights in delegating the problem upward to these energy agencies. You can tell Barry that we recognize the fun we are all going to have with this. Thanks, it was a very enlightening presentation.

MR. NAZEMI: Commissioner, I appreciate that and I will pass it on to Barry, but I think it was partly as a result of the Judge's state court decision that she wanted our agency to do the analysis that you are hearing five different agencies debating over, as part of our rule amendment, and we have no expertise to do that kind of analysis.

COMMISSIONER BYRON: Mr. Nazemi, thank you for being here. A quick question if I may, going back early in your presentation, you know, you made the comparison back to 2000, 2001, when we retired more than 5,000 -- I am sorry, we built more than 5,000 Megawatts of generation, while retiring 3,000 Megawatts, and I believe you said the net effect was an improvement for the environment. Would that be the case going forward if we were to build new efficient power plants and retire the aging ones that exist on the coast?

MR. NAZEMIU: On a pounds per Megawatt hour basis, yes. Now, if you want to sit down and look at each plant, I mean, we heard today some of them may have lower capacity than others, and we also heard at the same vein that the new power plants that are asking to run X number of hours, they do not really need that many hours. So it depends if you do an apples to apples comparison in terms of pounds per Megawatt hour, yes, the new plants are more efficient. You take a utility boiler that is only 29 percent -- has 29 percent efficiency -- compare it to even a simple cycle gas turbine that has over 58, 59 percent of efficiency, you can see that you will burn less gas and PM-10 is -- or PM-2.5 is the result, the direct result of burning natural gas. So if you want the same amount of Megawatts, you are going to be burning less gas to generate it.

COMMISSIONER BYRON: Thank you very much. Dr. Jaske was the first to the microphone, although I see we have a few others behind him. Please go ahead.

DR. JASKE: For the record, Mike Jaske. Your slide, third from the last, the supplemental comments of your colleague, raised SB 827 and I guess I am struggling to reconcile what you said about 827 with another part of your presentation. I believe 827 points you back to the pre-1315 offset tracking system, which I guess from state law perspective is sanctioning. But I also heard you say that USEPA was not happy with the pre-1315 internal bank tracking system, so will USEPA, in effect, sign off on a permit for a plant pursuant to SB 827?

MR. NAZEMI: Mr. Jaske, I cannot speak for USEPA, obviously, but the concerns that EPA had with our previous tracking system were related to some, in most part, to some pre-1990 credits, and as part of our agreements with EPA, we retired 93 percent of PM-10 pre-1990 credits that we had no longer maintained records for. And whatever remaining pre-1990 credits there were in the bank for all pollutants, we also retired in 2005. So the reason I -- and, by the way, state law or state court did not sanction the use of the previous tracking system, they sanctioned the use of 1315 tracking system. What I was trying to explain is that, if we go back to the previous tracking system, where we agreed to eliminate a major portion of the credits, a significant portion of the credits, and with EPA's agreement putting in place of those some new credits that were always credible and available to use, then you are going to find a bank that does not have enough credits to move forward to issue permits to anyone. So, as a result, the amount of credits that will be granted to LADWP or anybody else will not be supported by the old tracking system.

COMMISSIONER BYRON: Mr. Nazemi, I see another clarification coming forward.

MS. BAIRD: If the Commissioners would indulge me, I think Mr. Jaske -- or Dr. Jaske -- was asking, since SB 827 also refers to the old tracking system, why do we believe SB 827 gives us relief and allows us to go forward and issue permits. And the reason for that is SB 827 also says, in addition to the old tracking system, the District can use any emission reductions from minor source emissions reductions or minor source shutdowns that have occurred since 1990. We can rely on those credits to begin issuing permits. And those are the credits that we have relied on to replace the pre-1990 credits that, as Mohsen was explaining, we have discarded per our agreement with EPA. So that Bill gives us the mechanism to take account of the credits that have occurred since 1990, that meet federal requirements, and use them to rely on for issuing permits in the future. Thank you.

DR. JASKE: Okay, so if I understand what both of you have said, it is that this proposed legislation, or this bill that has passed the legislature, awaiting the Governor's signature, will recreate the legal pathway to provide internal credits to power plants, but that there is a very limited amount of such credits that are, in fact, available?

MR. NAZEMI: Two clarifications, it does not allow credits to go to new power plants, only to repowers --

DR. JASKE: Oops, yeah, I am sorry I said that wrong.

MR. NAZEMI: -- and second, the answer is, yes, there will be adequate amount of credits for power plants and all other essential public services and other projects exempt on their Rule 1304.

DR. JASKE: Thank you.

COMMISSIONER BYRON: Thank you. Please.

MR. VAWTER: Thank you. Don Vawter, AES Southland. Well, it is correct that the District did deny the permit application for AES High Grove. Really, we kind of gave up on that project. The District had asked us to demonstrate how we would come up with the ERCs to keep that project going forward. They were very patient with us, they gave us a couple of extensions, but at the end of the day, we could not do that and they said it was time to either demonstrate, or they would have to deny the permit application. We told them that was the appropriate thing to do at the time, so we would like to say we quit before we got fired. I just wanted to clear that up. We now look forward to working with the District as we intend to repower most of our 4,300 Megawatt OTC portfolio over the next 15 years, and our path forward is the 1304 exemption. Thank you.

COMMISSIONER BYRON: Good, thank you for the statement.

MR. MARTINEZ: Good afternoon. My name is Adrian Martinez and I am here on behalf of Natural Resources Defense Council. And I just had a quick question for the Air District. Does the Air District believe that the provisions of 827 allowing for use of minor source emission reductions needs to undergo EPA approval before being used?

MR. NAZEMI: We had already discussed the use of minor source shutdowns with EPA in a letter they had, in concept agreed with us using those. So we will provide it as part of Rule 15 re-adoption to EPA, but there is no concern raised to us by EPA relative to those minor source shutdowns.

COMMISSIONER BYRON: Mr. Carroll?

MR. CARROLL: Good afternoon. Mike Carroll with Latham and Watkins, and I also wanted to address this particular issue of what EPA has said, or what EPA has required because, in fact, what EPA has indicated is that it believes that it would be preferable for the tracking system to be reflected in a rule; however, they have never said that that was a requirement in order for the offsets being made available pursuant to the District's tracking mechanism to be federally enforceable. They have never disapproved a permit on the basis of the absence of the rule to date, they have never disapproved a district rule that made offsets available from that internal emission offset account based on the absence of the rule, so it is true, EPA does want to see a rule, but they have never said that the district cannot move forward, or that the credits that are in the District's internal emission offset accounts are not valid and available for use in satisfaction of all federal requirements until such time as that rule is in place. In fact, when they have gone on record in an official way, and spoken on the issue, they have said just the opposite. In a Federal Register Notice approving District Rules, what they said is that improving Rule 1309.1 in 1996, we, EPA, determined that the District's implementation of a tracking system demonstrated that the priority reserve bank's emission reduction credits complied with the requirements of Section 173C. And, again, in a letter dated April 11th of 2006, the EPA said -- this is a letter from Deborah Jordan of Region 9 to Barry Wallerstein of South Coast AQMD -- "We have reviewed the District's proposed revised NSR offset tracking system and believe that the system now addresses underlying historical issues such as the use of the pre-1990 credits, credits for the District's BACT discount, and the need to adjust aging credits retained in the system." They then go on that letter to say, "We look forward to seeing a rule," but they have never said a rule is required. And their actions clearly indicate that they do not believe a rule is required. Thank you.

COMMISSIONER BYRON: I thought that comment might elicit a response.

MR. NAZEMI: Thank you very much.

COMMISSIONER BYRON: Thank you. Thanks for being here and we appreciate the expertise that you brought with us, very helpful to have answers to these questions and the insight -- the latest insights that we are looking for.

All right, next is the Developer Observations on ERC Procurement and Requirements. And on the agenda, I show Mr. Larry Kostrzewa from Edison Mission Energy.

MR. KOSTRZEWA: Thank you very much.

COMMISSIOENR BYRON: Did I say that correctly?

MR. KOSTRZEWA: No, but nobody does. It is really okay.

COMMISSIONER BYRON: I apologize.

MR. KOSTRZEWA: Happens all the time.

COMMISSIONER BYRON: Please correct me.

MR. KOSTRZEWA: It is Kostrzewa.

COMMISSIONER BYRON: Thank you.

MR. KOSTRZEWA: Well, I come from the perspective of being a developer to quick start fast brown peakers in the LA Basin Local Reliability Area that we have developed to meet the needs that the various agencies and utilities have projected. One of them is the Walnut Creek Energy Park, and that one has a Final Determination of Compliance from the Air District, the final license from the CEC, and the power contract from Southern California Edison. We have a Bill similar to AB 1318 that made it through the Assembly, but not quite through the Senate, and so we look forward to completing that when the Senate resumes so that we can meet our PPA commercial operation date in 2013. The second project is one that has got a Final Determination of Compliance and a Preliminary Staff Assessment, but of course got held up in the permit moratorium. And, really, that is most of the thoughts that I will be expressing from that perspective.

COMMISSIONER BYRON: And just, if I may for clarity, which project is that?

MR. KOSTRZEWA: The Sun Valley Energy Project in Riverside County.

COMMISSIONER BYRON: And so, I am sorry, I am a little slow on the uptake, so the problem with the Walnut Creek one is you still need ERCs, correct?

MR. KOSTRZEWA: Well, that is the problem with both of them. We hope -- or we anticipate Walnut Creek probably being resolved through legislation.

COMMISSIONER BYRON: Well, it had everything else, it was just the ERCs.

MR. KOSTRZEWA: Correct.

COMMISSIONER BYRON: Okay.

MR. KOSTRZEWA: And the Sun Valley Project, obviously there are lots of presentations and lots of viewpoints, but bottom line, there is 5,600 Megawatts of capacity in the LA Basin Local Reliability Area that averages about 47 years old, and that is pretty old for a power plant. There are also not quick ramping or fast start and, you know, I am sure you understand that wind generation in California is primarily an off-peak resource which, when you have got power plants that have to stay on all night in order to be available for the day-time peak, that results in an increasingly more serious -- or over-generation problem at night, and already this year, in June, we had negative power prices as a result. And additional wind is just going to make that problem greater, so we really need capacity that can turn off when it is not needed.

From our perspective, a competitive market is key and for a competitive market to work, you have got to have multiple options that are permitted and ready to go. It is very dangerous to rely on permitting projects after the need is already identified. We really saw that during the California power crisis. We need to have those options ready and available, and then can pull the trigger on them when the need is actually there. And really, there has to be more projects permitted than will ultimately be built, otherwise there is no competition. You have just whatever has been permitted is your only option. And because of the scarcity of PM-10, and do not forget SO_x, ERCs in the South Coast Air Basin, we agree that some new thinking and policies would be called for.

I want to talk a little bit about some of the questions that were raised both in the discussions and in the panel question. One is the number of hours. Certainly, if you are building a peaking plant to solely meet resource adequacy obligation, the number of operating hours can be deeply limited. More efficient turbines, which in order to address the global warming problems, really need to operate more hours because they have an energy value besides just the resource adequacy value. And so they will tend to operate more and I will show you a chart on that in must a moment.

The cost is pretty amazing for these -- 400 or 500 Megawatt peaker. The ERC package would cost $50 to $80 million. Those are not real prices, it is scarcity, so it is whatever the market will bear. And when you look at that, that adds over 10 percent to the capital cost of building a peaker in the South Coast Air Basin. And when you are talking about those kind of dollars, it obviously does not make sense for a developer to purchase the ERCs, even if we could, which we cannot, just not that many are offered, and hang on to them in hopes that in some number of years down the road, we will be able to build a plant. So the need to have multiple options ready to go and the reality of the costs involved, just -- that does not work. And even if we could, having a bunch of power plants holding all those ERCs would only exacerbate the shortage if they were available, and they are not.

The Rule 1304 exemption for electric utility steam boiler replacements is only available to three suppliers in the South Coast Air Basin -- AES, NRG, and Reliant. And that does not provide enough competition to assure the least cost to ratepayers, so we need solutions beyond just Rule 1304. Some parties have suggested that, well, power plant shutdown credits could be a solution, but it is not, really. The new plants must be built before we shut down the old plants, so there is a timing problem. Secondly, the Air District's rules for determining how many shutdown credits you can qualify for are really designed to minimize the supply of credits, but the offset rules that we have to follow to build a new one are really designed to maximize the need for those credits, and so there is just a fundamental mismatch there, too. And lastly, again, power plant shutdown credits, they are just essentially a three-party oligopoly there.

There are a bunch of solutions. I put up here an excerpt from a slide that the Air District shared with their NSR Working Group, and we really encourage them to keep working on that, it is great out-of-the-box thinking, and that is what we need. I circled a few of those, and those are the ones that I will address going forward.

COMMISSIONER BYRON: Forgive me, NSR -- is that New Source?

MR. KOSTRZEWA: New Source Review, I am sorry, I broke the acronym rule already. Here is a chart that we pulled together from some data that the Energy Information Administration publishes. It shows capacity factors of power plants in Southern California plotting their capacity factor against their heat rate. And I think it refutes, first of all, the idea that the existing units in the Basin are efficient. As you can see, the existing units are the ones off to the right that are actually quite inefficient. And the red line there represents the GE LMS 100 turbine that we are planning to use for our Sun Valley project. It is quite a bit more efficient than the existing stock. And although it is hard to draw a line through all those points, you can see, as the plant gets more efficient, it is economic to run more. The question of exactly what capacity factor the plant will run at will depend on the weather -- is it a hot year, or a cold year? How much hydro do we have from the North? And various other factors. But in order to have a useful asset in the LA Basin, we do have to permit for the extreme condition.

And this table here attempts to really illustrate the impact of all those assumptions. There are a lot of numbers there and I will try to walk you through line by line.

COMMISSIONER BYRON: You know, I am just going to ask you if you could go back to that last slide just a second.

MR. KOSTRZEWA: Certainly.

COMMISSIONER BYRON: The way you made the statement, that you have got to develop the project for the extreme condition, but I think the other way we have been hearing that statement made is that what you need to ask for is you need to ask for a lot of ERCs because you might need to run a lot more than 10 or 20 percent of the time.

MR. KOSTRZEWA: That is right. What are we going to do if it is a hot summer and it is dry hydro year like we had in 2001? You just have to run all those hours. It would be bad if we say, "Sorry, we're not permitted to run anymore hours."

COMMISSIONER BYRON: All right.

MR. KOSTRZEWA: So this next slide looks at really how our -- how Sun Valley's PM-10 offset requirements are determined. Starting with what we think will happen, the GE turbine will probably emit about 4 pounds per hour for each turbine of particulate emissions, but GE, being cautious, of course, will only guarantee 6. But if we could offset based on our expected operation, and we plan on a 1 and 2 summer, a typical summer, we have maybe a capacity factor of 20 percent, looking at kind of a high number from the prior chart. If we could average the quantity we would need over the whole year, we on average over the year would emit 102 pounds per day, and multiply that by 1.2 and we would need 122 pounds per day. Well, in fact, we are uncomfortable permitting at the emissions we expect. We want to permit at the emissions that are guaranteed because we need to get bank financing, and the banks will say, "Well, guarantee me that you are going to meet it." So we have to use the 6 pounds per hour. Well, the result of bumping up to 6 pounds per hour is now we need 183 pounds per day of the ERCs. Well, another factor, too, is, to be a useful resource in the Basin, we need to plan not just for an average summer, we need to play for the 1 in 10 summer, which I think was mentioned in one of the earlier slides. In a 1 in 10 summer, at least our calculations suggest, the plant might have to operate 35 percent of the year -- not ever often, only once every 10 years, but it could happen. Well, suddenly our offset requirement jumps to 313 pounds per day. Add to that, now, the requirement in the Air District's interpretation of their rules that the offset requirement needs to be based on not the year as a whole, but the maximum month, which of course for a peaker is July and August. Well, if we want to operate during the entire on-peak period in July and August, that is 16 hours a day, six days a week, that bumps the offset requirement to 525 pounds per day. That would be 59 percent of the time, you know, as an extreme case, we hope it would never happen, but that might happen some July or August if it is really really hot.

And then the last step, just some curiosities of the Air District rules, even though our plant is able to start up in 10 minutes, and only the last three minutes of that are we actually burning fuel, for modeling purposes, the start-up is traded as a half hour. Well, so peakers start often twice a day, so there are a lot of starts and that adds up. And secondly, we take the maximum month which is July and August, each of which has 31 days, but we have to divide it by 30 days because that is another rule. Now we end up with an offset requirement of 555 pounds per day for, ultimately, actual emissions in the air of about 102. That gets further exacerbated 30 years from now, 40 years from now, when we shut down the plant, we would only be able to credit offsets equal to actual operations at actual capacity factors, which, you know, 30 or 40 years from now, with technology advancing, might only be half of the 102, and that of course contributes to the offset shortage.

COMMISSIONER BYRON: So are you putting this table together here -- I mean, it is very informative -- but are you suggesting that this is something you have to live with? Or are you suggesting that maybe the Air Board should look more closely at the details of these rules?

MR. KOSTRZEWA: Well, these are the outcomes of the rules and, under my list of solutions there, you know, I recognize SB 288 is a high hurdle, but in terms of what might we hope and dream for, one way to solve part of the problem would be, if we permit at six pounds per hour, and when we build the plant we test it at four pounds per hour, it would be nice to get those excess ERCs back and put them back into the market. So that would be solution number one. The second step would be, you know, recognizing plants have to be able to operate for that 1 in 10 summer, but that almost never happens. If we could offset for a typical year and maybe keep some running average from year to year to make sure that we are not actually over-emitting, that would also significantly reduce the number of offsets we would require. Another one would be to offset based on capacity factor, rather than strictly operating hours. One of the big benefits of the fast start -- or quick start fast brown peakers is that they will be able to go up and down a lot because, as a developer of wind and solar, we know wind and solar go up and down a lot, and gas-fired generation is going to have to compensate for that. So we will, in a lot of cases, be operating at low loads, at minimum load, so that we can pick up in the event a cloud passes over or the wind slows down. And even though we might operate 20 percent of the hours, we probably will not operate at 20 percent capacity factor, for example. A lot of times, the plant will be running just for ancillary services. Of course, one of the obvious ones, the biggest impact, is really going from the average month to the maximum month, if that could be changed, that would be just great. And some of those curious aspects of the rules that artificially extend the start duration, or assuming that the maximum month has 30 days instead of 31, you know, could save us a few more -- it is not a lot, but it is still a few percent.

VICE CHAIR BOYD: A question if I might.

MR. KOSTRZEWA: Of course.

VICE CHAIR BOYD: Your proposal to offset for typical year, not 1 in 10, what happens when the 1 in 10 shows up? Are you going to have a bank of credits stashed away of your own that you could dip in to use? Or do you have some other suggestion for how that deficiency in that year is addressed?

MR. KOSTRZEWA: Well, it is not a very well formed proposal, but I believe that we could keep track from year to year of our operating hours. And if the limit was not a number of hours per month, or a number of hours per year, but operating hours over a sliding five-year window, for example, I think we could reduce the volume quite a bit.

VICE CHAIR BOYD: Thanks.

MR. KOSTRZEWA: Another thing we deal with as developers, if there are not enough on the market, you know, can we create offsets? And one of the barriers to that is, again, the way some of the rules are designed. The chart on the left does not mean much in terms of actual numbers, but there is an emissions source that we have been talking to that emits, say, at 100 percent, is their current emissions, and by applying some additional control technologies, we could reduce their emissions down to that little bitty remaining part. And so the air cleans up by that whole amount that is shown as emission reduction, but under the Air District's rules, the amount of offsets we can actually create is first discounted by assuming that the source should go down to best available control technology, and the only emission reduction credits that can actually be certified are those, to the extent that best available control technology is exceeded. The problem is the certifiable amount becomes very very small, and the cost of the controls spread over the whole volume actually would work, but the cost of the emission control is spread over that tiny amount that is actually certifiable is prohibitive in most cases, and results in a missed opportunity to clean the air and contribute towards solving the offset problem. Solutions there, obviously, take another look at those rules to facilitate ERC creation.

Another potential solution is for the Air District and the CEC to certify a power plant on the condition that, before we start construction, we must deliver ERCs. That would allow us to get through the permitting process and be ready to go with obviously a huge hurdle ahead of us, but would have projects ready to go, but for either creating or obtaining ERCs, and then, although not related to this chart, another solution would be to allow new generators to opt into the SO_x reclaim program. Right now, we are required to provide SO_x ERCs which are also in short supply. Electric utilities are allowed to opt into the SO_x reclaim program, but really independent power generators are the major source of new generation, and you know, if one were to really take the position that IPP plants are now serving that need, particularly if you are contracted with that utility, that would solve that problem, or at least address that problem.

And lastly, also related to ERC creation, the Air

District has really done an amazing job over the last, well, 20 years at least, in eliminating stationary source emissions, particularly squeezing down the electricity generation sector. Those charts there are from the AQMD's 2007 Air Quality Management Plan, and those are pie charts showing where the PM-10 and PM-2.5 emissions in the Air Basin are coming from, and as you can see, electricity generation is only a tiny sliver there. It makes it very hard, well, and if you look at other stationary sources there, those are also tiny slivers. In order to really be able to create new emission offsets, we are going to have to be able to access non-traditional sources like area sources and mobile sources, which is a problem because, particularly, the mobile sources have a shorter lifetime than electricity generation facilities do. But one possibility is to over-control and clean up the air a whole bunch up front, and equivalent to what the emissions would be with the life of the power plant. And that is all I have got.

COMMISSIONER BYRON: Well, very good. And a lot of new material, some helpful ideas. Any response from anyone or questions?

MR. VAWTER: Don Vawter with AES Southland. I would just like to make a couple of comments about Mr. Kostrzewa's assertion that we would, through the Rule 1304 exemption, be in a position to exert market power at the expense of the ratepayers. First of all, I would support most, if not all, of Larry's proposed fixes to ease the pressure on the ARC market, and would be glad to then bid against his proposed project in an open RFO. The Brownfield project is always going to have a cost advantage over a Greenfield project, and we have no problem demonstrating that through an RFO. Secondly, there are many ways to ensure that a power plant developer is providing a fair and adequate price. There are reams of public data about what it costs to build site and operate generation, third party engineering studies could be done to verify that. I think it is an overblown concern, frankly. There is also, through AB 1576, which passed into law a few years ago, the opportunity for utilities to get full rate recovery by negotiating repowers of OTC units that, on an open book negotiation basis, and we would be willing to do that. Thank you.

COMMISSIONER BYRON: Mr. Nazemi, I wonder if you -- and I do not mean to put you on the spot, but some of these that are offered as solutions, and I would characterize them more as suggestions on Mr. Kostrzewa's slide 5 with regard to how to recalculate more -- let's say discreetly calculate the emission credits. Do any of these make sense? I guess the question that I have is, are the responses to each of these, not that you should have to provide them now, as to why the Air Board calculates this the way it does --

MR. NAZEMI: -- power plant, for example, actually these are not only in our rules and regulations, but they are also requirements under the federal law that, in order for an emission reduction to be valid, it has to be real. And you cannot say that the facility was permitted to emit this many emissions, therefore, when they shut down, they should get all of those as credits; you have to show that they were real. So that is why we look at a past number of years of operation and calculate how much emissions they have. Contrary, for a new power plant, federal law requires the emissions to be offset at its potential to emit level. So, again, that is a requirement that we have to follow. Now, there are certain specific language in our New Source Review Regulations that directs us how to calculate the emissions, you know, look at the 30-day average for a maximum month, actually the language in our rules requires us to do that. The slide that Larry put on the screen that these are some ideas, they are in fact ideas that we are looking at, but as I indicated earlier, almost all of those ideas required a rule change, and once we do a rule amendment, we need to adhere to Senate Bill 288. So it does have some issues associated with it, not that they are impossible, but it is not just a staff position that we are doing it this way, because we like to, it is the requirement in our rule.

COMMISSIONER BYRON: Good. Thank you, Mr. Kostrzewa, but I think in the interest of time, I am going to ask that we move on. We could spend a great deal more time talking about some of the material you presented us, and I appreciate it very much. I believe Mr. Carroll is next, from Latham & Watkins.

MR. CARROLL: Good afternoon. I am Mike Carroll with Latham & Watkins, and just by way of introduction, I guess it probably is apparent by virtue of the panel that I am appearing on, but just in the interest of full disclosure, I do represent many of the CEC jurisdictional projects proposed in the South Coast that have been affected by these issues, in addition to many many non-CEC jurisdictional projects that were affected by some of the collateral impacts associated with the litigation surrounding these issues. And we also represent all of the private parties that are party to both the state court and the federal court litigation.

One of the benefits, I suppose, or the problems, depending on how you look at it, following so many good presenters on a topic is that many of the issues that I had intended to cover have been covered already. So, in some cases, I will move through my slides relatively quickly. There is a lot of information here, and I know we are running a little bit behind, as I said, because some of this has been covered, I will try to move quickly through a number of these slides.

COMMISSIONER BYRON: Thank you. I appreciate it, but I do want you to make sure you feel free to cover your points adequately.

MR. CARROLL: I appreciate it. I will do that. I think an important point that I want to make is to debunk what I think has been a myth that has been created surrounding this set of issues that, what we are faced here is with a choice between having adequate electric reliability to meet the needs of our citizenry, and to maintain a stable economy, and protecting the environment. And quite to the contrary, we think that the proposals for a new gas-fired generation in the South Coast District accomplishes both of those objectives, or all of those objectives, and that we really do not have a trade-off here between electric reliability and environmental protection.

As has been seen in many of the presentations that have been made already, we think that there really is a need to develop new gas-fired generation in order to meet the electric reliability needs in Southern California. The extent to which you believe that need exists varies and we have seen different presentations, depending on what assumptions you put into your analysis, or into your model, you will come out with a different number. But I think that, regardless of which analysis you look at, it is clear that there is a need and I think we need to be cautious, and there has been some recognition and discussion of this today about the assumptions that are made because, assuming that we need X Megawatts of gas-fired generation, or assuming that we need X Megawatts of renewables, or assuming that we need a certain amount of transmission and moving forward, assuming that we therefore have a plan, can be very dangerous because, as those of us -- and I include the Commissioners in this -- that are involved in the siting of these projects know, saying that you need X Megawatts and getting X Megawatts approved and on the ground and operating are two very different things. So I think we need to be very cautious about the assumptions that we make in these models.

The other thing that I would say, with all due respect to all the engineers in the room, is that sometimes the analyses or the models have a degree of logic in them that have no place in environmental regulatory realms, and so, while we can all sit and say that it makes sense that you should offset your emissions based on what you think your emissions will be, or that you should be allowed to generate credits based on what your emissions reductions are, as we have seen from Mr. Kostrzewa's presentation, the rules do not always work that way. And so we always need to factor in the somewhat artificial and somewhat illogical constraints that we sometimes have with respect to the regulations.

Again, what I have done here is really summarize much of the analysis that has been presented to date. There are a number of quotes here, firm reports prepared by entities that have spoken today, and I am not going to read them, you can do those now, or do those later to the extent that you do not have time now. But they really pull together what, for me, were the bottom line conclusions of some of these analyses. It is clear that without the ability to develop new generation in the South Coast, we are running head long into the Rule 1630B requirements for once-through cooling, and that we are not going to be able to address that problem in its entirety through transmission.

It is also clear that the state has recognized that because of that constraint and others, that the potential for not being able to meet the needs of the Southern California Region is a very real potential, and that is a high risk issue that the state needs to pay immediate attention to, and that the consequences of failing to pay attention to that issue are very significant to our economy and that the repercussions of not being able to supply the electricity demand in the Southern California region could be devastating to the economy at a point in time where we obviously can least afford actual disruptions to the economy or, frankly, even the threat of a disruption or a great uncertainty associated with a threat of a disruption.

And setting aside the economic consequences of the inability to meet demands for electricity are all the secondary environmental impacts that go along with those, and I do not have any bullet points here, but what we saw in the 2001-2002 timeframe, I am sure that the district would back me up on this, is that when we are unable to meet the demands of the region from the grid, what we see are secondary back-up sources of generation coming online, diesel-fired emergency generators and other similar sources, with really dramatically higher impacts and public health issues associated with those back-up sources of generation. So the failure to address this issue and meet the demand, and ensure that we have adequate supply to meet that demand is not just an economic issue, but becomes a very real environmental and public health issue, also.

As I said, meeting those needs from an electrical reliability standpoint is not at the expense of environmental protection. When we look at the sources who have pointed out the need for new generation to meet the electric reliability needs, what we also see is that those very same sources are pointed at the need for new generation to meet the environmental needs. So you see some of the same conclusions and the same quotes here that support the need for new generation for reliability supporting the need for new generation to meet the once-through cooling requirement amongst other environmental regulations.

We have identified, or the California Energy Commission has identified very specifically a number of plants that will not be able to be taken offline as hoped, or as planned, in the event that new infrastructure does not become available. We, as developers and proposers of new projects, are frequently asked, "Well, if your project comes online, which one will come off?" That is a very difficult question to answer for a lot of reasons that I do not have time to get into today, but it is a difficult question to answer. A much easier question to answer, frankly, is if we do not come online, these are the projects that will not come offline. And we are very capable of identifying what those projects are, and here are a handful of them.

With respect to the air emissions, and we spent a lot of time talking about the once-through cooling issue today, but obviously the new plants come online with state-of-the-art emission control technology, and on a per

Megawatt basis, are much cleaner in terms of all the criteria pollutants that are listed here, than in the existing generation. And, of course, as I said, we have covered the water quality issues I think pretty adequately today.

Another advantage from an environmental perspective of bringing the new generation online is the support for the intermittent renewable sources. And, again, this is a point that has been touched on. The natural gas-fired generation firms up the intermittent renewables, and in addition, it frees up transmission to import renewable energy, which almost exclusively comes from outside of the South Coast Basin. So if we have any hope of meeting our goals with respect to renewables, we really need the gas-fired generation to back that up. There has also been a lot of discussion today about the ancillary services. Here are some quotes on that particular issue from the Energy Commission, and the need to consider in the analysis the ancillary services provided by the natural gas-fired generations. And I think Mr. Turner and others made very good points to this effect, that we cannot analyze any single piece of this puzzle to the exclusion of others, but really need to take into consideration all the various aspects of the puzzle in order to find out effective solutions, and the ancillary services are certainly a part of that.

Moving on to the state's greenhouse gas reduction goals, and obviously this is very much tied to the support that the gas-fired plants provide for the renewables, this particular graphic, I am sure, is difficult to read from the back of the room, as is the one here, but the points that are made by the two graphics are really those that are made in the bullet points here, which is that the addition of the new gas-fired plants are necessary in order to support and back-up the renewable generation, and that if we hope to achieve the greenhouse gas targets, we are going to need to move to a greater reliance on renewable energy, and we can only do that if we have got natural gas-fired plants there to back it up when that inherently intermittent renewable energy is not available. And then, finally, the addition of the new gas-fired plants improves the overall efficiency of the electric system. Again, I think that is a point that we have hit on repeatedly today. I do not know that we have really talked too much about it in the context of meeting our greenhouse gas reduction targets, but the ability to support and have a reliable electric system that is heavily reliant on renewables, which is what we are going to have to have to meet the greenhouse gas reductions, is obviously very dependent on having the natural gas-fired plants to back that up.

So just in summary, and I will not read through these, but our view is that this is not a trade-off, that it is sort of a -- not sort of -- it is a classic win-win situation where these new natural gas-fired projects not only allow us to meet the reliability and the electrical needs of the region, but also are critical to advancing the environmental objectives of the region.

So what is standing in our way of implementing what I view as a classic win-win? In large part, but certainly not exclusively, because as we all know, there are many many issues that affect these projects, you know, this is just one, and sometimes I think we lose sight of it, and it is a critical issue, but developers that are faced with these projects face hundreds or thousands of regulatory requirements, many of which are very thorny. The emission offset issue is a couple of lines in the Clean Air Act, it is one of thousands of requirements that need to be dealt with in connection with siting these plants, but it is a very important one. As has been discussed, the emission offset requirement comes from the New Source Review Program embodied in federal, state and local law, which has three major components, the requirement to install best available control technology, the requirement to do emissions modeling to demonstrate that you will not exceed or contribute to an exceedance of an air quality standard, and the one that we are talking about today, the emission offset requirement. I think it is important to keep in mind that the New Source Review offset requirement is a mandatory requirement, and I think frequently there is confusion between this requirement and "market-based" or "market incentives" programs, or economic incentives programs, that are put in place to provide flexibility for compliance. So, for example, there are programs out there, which we think frequently make a lot of sense, that will allow a facility to avoid installing controls, provided they obtain a marketable emission reduction credit from another facility. That really is a compliance flexibility mechanism, it is a way to achieve the environmental objective at a lower cost. That is not what the New Source Review offset requirement is. The New Source Review offset requirement is a mandatory requirement that you need to comply with on top of everything else. So you are not getting out of anything, the ability to buy credits from other sources is not some sort of an economic incentive or an economic break, it is a mandatory requirement, so it is very different, for example, from the reclaim program in the South Coast, which really is intended to be a compliance flexibility program.

The current offset markets, at least with respect to some pollutants in the South Coast, are dysfunctional. The supply is diminishing. The reason for that is that the traditional sources of supply has been the shutdown of existing facilities, or the over-control of existing facilities. So generally the private market was funded by credits that came from typically large facilities that shut their operations down, moved them out of the Southern California area, or just shut them down completely, and applied for emission reduction credits based on their emission reductions. Or, they were based on facilities that controlled their equipment beyond the level otherwise required, and then sought emission reduction credits for the margin between those two. We do not have a lot of big industry left in Southern California other than that which is sort of geographically tied because it is tied to infrastructure that cannot be easily moved or it is tied to being on the Coast, but things that could move out of the South Coast, for the most part, have. You know, the auto industry is a good example, furniture manufacturing is another. So we have gotten to a point where you do not have a lot of sources shutting down in Southern California in any given year, and therefore there are not many opportunities to generate credits. The businesses that are there have been very heavily regulated, so the ability to go above and beyond and generate credits through over-compliance, has also been diminished. And then, finally, as has been mentioned, the credit generation rules are extremely stringent, and so there is very little relationship between your actual emission reductions and what you get in the way of a bankable emission reduction credit. At the same time, while the supply has been diminishing, the demand has been steady with spikes. Existing facilities do need to modernize, they do need to upgrade, they do need to put in new equipment from time to time, and that generates a demand, a rather steady demand, for emission reduction credits, and every once in a while we have a spike, like in 2001-2002, and 2005-2006, where we have a slug of power plants, for example, coming through. So the demand continues to grow while the supply has diminished. And, as I said, the problem does vary pollutant by pollutant with PM-10 and SO_x being the most serious problem right now.

In terms of possible solutions, Mr. Kostrzewa mentioned some of these. We need new credit generation programs, and we need to look certainly outside of the electric generating sector, and outside of the stationary source sector, in order to find new credit generation opportunities. The opportunities for emission reductions, if you look at the pie chart from Mr. Kostrzewa's presentation, are from the mobile sector. So we need to develop more programs to generate credits from the mobile sector, and that includes on-road and off-road fugitive dust, and we have had some projects permitted based on road paving generation of credits, the South Coast began to undertake an effort to go down that path that, frankly, has been stalled. We would like to see that re-started. But certainly, the mobile sector, whether it be tailpipe emissions or emissions associated with fugitive dust, needs to be tapped into to generate additional credits. We need more rationale offset requirements and very sympathetic to what was not said, staff does not impose the requirements because they want to, or they think it is a good idea, they are right that that is what the regulations require, but we need to look at those regulations and make amendments where appropriate. And staff is also right that we need to take state law considerations, specifically SB 288, but I do not think we can just sort of throw up our hands and say, well, it requires a rule amendment, and we have to deal with SB 288, so that is the end of the analysis. I think we need to undertake those difficult efforts if SB 288 is a problem, then make SB 288 needs to be addressed. And as we have seen in the recent legislative session, the Legislature is willing to step up when necessary to address problems like this. And so I think it is very important that we focus on imposing some more rationality into some of these requirements in terms of determining the amount of emission offsets necessary for a project. We need greater flexibility from the staffs at all agencies, frankly, including the California Energy Commission, to be creative in the way we come up with emission offsets. We have used, and continue to use, such things as intra-district and inter-Basin offsets, that is typically a very complicated and difficult process, it needs to be made a little bit less complicated and a little bit less difficult. We have also used inter-pollutant offsets. We think that these are very viable mechanisms and we would like to see more receptivity on the part of the staffs of all the agencies to these creative proposals.

And finally, we think the District's internal emission offset accounts are a valuable and viable source of emission offsets. We have heard that recent legislation has been passed that will allow the District again to tap into that for certain types of projects, unfortunately not CEC jurisdictional projects, but we have also heard that AB 1318 was also passed by the Legislature, which will allow the District to tap into those offset accounts for at least one CEC jurisdictional project, and then hopefully we will see some legislation in the next session that will expand that to two other projects. So we continue to believe that that is a very viable source of offsets. They should not be focused on to the exclusion of everything above it, but it should continue to be on the list.

And then, finally, something that I just want to touch on, I really will not get into it, is reconsideration of whether the emission offset requirement really makes any sense anymore, given the situation in California.

COMMISSIONER BYRON: Mr. Carroll, if I may interrupt, please, with a question. And you may have described this already and I am just missing it with regard to the terminology because I am not an emission credit reduction expert. But Mr. Kostrzewa's last point in his last slide was the rule -- if I may just read it -- "Rule changes needed to allow stationary sources to use ERCs from other sources." Is that described in your list, as well?

MR. CARROLL: Yes.

COMMISSIONER BYRON: It is? Which one is --

MR. CARROLL: That would be the New Credit Generation Programs from the mobile sector, I think, is what Mr. Kostrzewa was referring to primarily.

COMMISSIONER BYRON: All right, thank you.

MR. CARROLL: There has been a lot of discussion about the District's internal emission offset account. I have highlighted that as one of the items from my list because it is one of the primary topics for discussion today. I think it is important to recognize that that is a very long standing source of emission offsets in Southern California. Use of those offsets to permit projects did not just arise in 2006 or 2007, it goes back many many years in the District, with the approval of all of the oversight agencies, including the California Air Resources Board and the U.S. Environmental Protection Agency permitted many many sources pursuant to Rule 1309.1 and Rule 1304, using emission offsets from its Internal Emission Offset Accounts. Those offset accounts have been determined by all of the agencies, including South Coast, the Air Resources Board, the USEPA, and the California Energy Commission, which has approved many projects in reliance on emission offsets from the District's Internal Emission Accounts. Those programs have been determined to be compliant with all the applicable requirements that apply to emission offsets by all of those regulatory agencies. We have not had any adverse court rulings that go to the validity of the offsets in the District's Internal Emission Offset Accounts, so we had an adverse court ruling in state court, but I think it is important to keep in mind that that was a CEQA lawsuit, and what the judge said was that the District failed to comply with the California Environmental Quality Act when it adopted the rule to make offsets available to power plants. It did not get into whether or not the offsets in the district's internal accounts applied with state law, or federal law, certainly. It was a CEQA lawsuit. By the same token, we have pending federal litigation. That litigation has been dismissed on jurisdictional grounds and no ruling has been rendered at the federal level regarding the validity of the offsets in the district's internal accounts. So, as I said, all of the agencies with regulatory over-sight over those emission offsetting accounts have deemed them to be compliant with state and federal law, and no court ruling at the state or federal level has said anything to the contrary. And as I indicated in my comments from the podium, there has been a lot of speculation about what EPA thinks of the District's internal accounts. I think they have been very clear what they think about the District's internal accounts.

The other point that I think is very important to remember about the use of the District's internal accounts are the mitigation fees. And we have not talked too much about those, but when a source buys credits from another private party, the private party gets that money and puts it in their pockets. And I am not opposed to private parties making money or making a profit, I mean, that is the way our system works, but one of the tremendous advantages associated with a source going to the AQMD to obtain its emission offsets is that the mitigation fees that would otherwise go to a private party go to the agency, and that are expended in the communities where the project is going to be located on an emission reduction project. So you are really getting a twofer, if you will, when the credits come from the agency. You are getting the reductions that are behind those credits in the first place, and then you are getting additional reductions on top of that, that can be generated with the TARP funds.

And I also want to put to rest this notion that those credits are made available at a discount, somehow. You know, we saw a presentation earlier where Mr. Nazemi said that there have been trades at the $350,000 a pound range. That gets translated into, well, if you let a pound go for anything less than $350,000, you know, that is a deep discount, or that is a give away to the power sector. Nothing could be further from the truth. Those are aberrational prices that are a function of a completely dysfunctional market. When the 1990 amendments to the Clean Air Act were adopted, the maximum cost that was projected for compliance with those requirements, including these offset requirements, was $25,000 a ton. We are not spending $350,000 a pound, so clearly something has gotten completely out of whack. The fact that somebody who was absolutely desperate to move forward with a project and needed a pound, was willing to go out and spend $350,000 does not mean that that is the market price that should therefore be applied to a power plant that needs 200 pounds to move forward. So I think that is a very important point to keep in mind when we are looking at the pricing.

This really is reflective of things that we have talked about today, again, I did not know how much of the background we would get into when I put together this presentation, but obviously there was rulemaking in 2006 and 2007 to make offsets available to the power sector that involved an amendment of Rule 1309.1 and the adoption of the tracking -- we have talked about Rule 1315. That precipitated state court litigation, again, a CEQA case filed in August of 2007, decided in July of 2008, with a writ issued in -- that should be November 3rd of 2008, that is a typo, not 2005 -- which set aside the rulemaking and set aside any actions that had been taken pursuant thereto. As has also been mentioned, that writ was modified just recently in September of this year to allow the District to permit sources pursuant to essential public services pursuant to 1309.1, and 1304, exempt sources -- the District has some views about whether that writ really provides the flexibility that they need to do that. We understand their point of view on that. The state court litigation is currently on appeal.

And then we have federal litigation filed in August of 2008. This is a Clean Air Act citizen suit brought by essentially the same group of petitioners that alleged that the offsets failed to meet the requirements of Clean Air Act section 173. As I mentioned, that case was dismissed on jurisdictional grounds in July of this year. We are waiting for a final judgment to be entered on that decision.

It has also been discussed, there was a legislative response, SB 827, which is sort of the broad scoped rule which reinstates the rule 1304 exemptions, and the ability of the district to permit essential public services pursuant to 1309.1. It allows the district to fund its internal emission offset account so that it can do that. That is the provision that the district believes is critical in the legislation that is not present in the Judge's modification of the writ. It does not make offsets generally available to CEC jurisdictional projects, so there were previous iterations of SB 827, and before it became SB 827, it was SB 696, which would have allowed the District to make credits generally available to CEC jurisdictional projects, but the final bill did not provide for that.

And it has also been discussed, AB 1318 was also passed, and that is a project that would allow the district to make offsets available from its internal accounts to certain qualifying CEC jurisdictional projects. The CPD Sentinel project is the only project that has been proposed that meets the qualification criteria pursuant to 1318. Again, we do not have time to get into this. I think there is a real question about whether or not the emission offset requirement makes any sense anymore. In my view, it has become counterproductive from an environmental perspective because, if you cannot get offsets to build new things, whether it is a power plant or an oil refinery, or a boiler, what do you do? You just keep operating the old thing. And so we do not get upgrades, we do not get the advantage of new technology, so in my view, the emission offset requirement has really become obsolete. This is something that requires, obviously, legislative fixes at both the state and the federal level in order to address, and is certainly beyond the scope of our discussion today.

Implications for CEC jurisdictional projects -- and this is really the wrap-up. I think it is certainly true that we need new natural gas-fired generation to meet both reliability needs of the region, and to achieve our environmental objectives. It is also absolutely true that, notwithstanding recent developments in the Legislature, that the emission offsets remain an impediment to achieving those goals. We think multiple solutions will be required, and a lot of them have been put on the table today - more rational offset requirements, additional offset generation programs, more flexibility in the way that the offset requirements are implemented, and support for AB 1318 and future legislative initiatives. We do not think that any of these require environmental compromise. We think all these solutions can be implemented with adequate protections for the environment. And we think that everybody needs to participate in these, and I certain understand the frustration that the District feels, they stepped out in a very significant way, have got a lot of litigation and a lot of grief for their efforts, but, frankly, they are part of the problem whether they like it or not, the Air Resources Board is part of the problem, when it comes to SB 288, the Legislature continues to be -- I should not say "part of the problem" -- part of the solution. I think all of the agencies need to be part of the solution here and none of them can wash their hands of this, we really need everybody at the table as we have today in order to move this forward. So with that, I will conclude, and thank you very much for allowing me to be here today.

COMMISSIONER BYRON: Mr. Carroll, very good. Were there questions or comments?

MR. MARTINEZ: I just have a quick question and --

COMMISSIONER BYRON: Please identify yourself.

MR. MARTINEZ: I am Adrian Martinez from the Natural Resources Defense Council.

COMMISSIONER BYRON: Thank you.

MR. MARTINEZ: I guess my question -- are you encouraging the CEC to promote amendments to SB 288 and amendments to the Federal Clean Air Act? Is that the suggestions at the end of the presentation?

MR. CARROLL: I do not think anything should be off the table at this point. I think that the emission offset situation, and, you know, we have been very focused on South Coast, but let me tell you, this is coming all up and down the state, and we are already seeing it in other areas where we are coming to the point where we cannot permit anything, no matter how environmentally beneficial, because of the emission offset requirement. And so I think everything should be on the table. I am not necessarily encouraging anybody to do anything today, other than look at all the options and reach their own independent conclusions about what options they think they should pursue.

MR. MARTINEZ: Thanks, that is helpful.

COMMISSIONER BYRON: Dr. Jaske.

DR. JASKE: I just have one clarifying question. In this slide, but perhaps more so than in the previous slide, you -- yes, that one -- well, in any event, you are using a very special kind of jargon -- CEC jurisdictional projects. What is your thinking about the South Coast 1304 exemption for repowers and whether those are CEC jurisdictional projects?

MR. CARROLL: Well, I think some of those are CEC jurisdictional projects, some of them are not, you know, depending on whether or not they otherwise meet the requirement to be within the jurisdiction of the CEC. So I do not think the emission offset issue has any bearing on whether or not they are CEC jurisdictional. 1304 exemptions would be available for some CEC jurisdictional projects; there are other projects that could qualify for 1304 exemptions that would not. So I do not know if that answers your question or not.

COMMISSIONER BYRON: Dr. Jaske, would you please come back up and answer this question. What would be non-jurisdictional for the CEC in the South Coast? What would be a non-jurisdictional repower?

DR. JASKE: I believe there is a portion of the Public Resources Code that establishes a constraint on our jurisdiction over a power plant, no matter how big it is, that if it is not more than 50 Megawatts larger than the prime mover being replaced, that it is -- that we do not have jurisdiction, it is some county or city in which it is located. And so, to the extent that 1304 becomes the path that is available to generators, by generators choosing not to have a net increase above 50 Megawatts, they have a completely different permitting process, and one that does not evidently involve the Energy Commission.

COMMISSIONER BYRON: Right, for instance, the Scattergood at 803 Megawatts could go to 852 Megawatts and not be jurisdictional?

DR. JASKE: That is correct.

COMMISSIONER BYRON: So -- go ahead, Mr. Carroll.

MR. CARROLL: I will also point out, and we have been very focused on the repowering provision in 1304, there are other exemptions in Rule 1304, including an exemption for resource recovery projects. We have many many energy projects that are not subject to the CEC jurisdictional landfill gas projects, municipal solid waste energy projects, that have been bogged down as a result of this litigation, that would also be able to move forward under 1304.

COMMISSIONER BYRON: Mr. Carroll, thank you. Very good.

MR. CARROLL: Thank you.

COMMISSIONER BYRON: And I apologize, we could go on with further discussion, but we have still many presentations to go. And we are behind schedule for a panel discussion. I believe Mr. Sciortino from the City of Anaheim is the last of our presenters.

MR. SCIORTINO: Thank you, Commissioner. I find myself in an unusual position of being last on the agenda, typically Anaheim enjoys the alphabetical advantage of going first. I want to thank the Commissioners for the opportunity to talk about our canyon project today. Thanks for the invitation to speak. I was going to talk a bit about our experience with our whole process. I want to caveat my comments in that Anaheim -- this canyon project is the first project we built in 20 years, so while the licensing process is very familiar to everybody in the audience, you will have to forgive us in terms of our inexperience with the process, and maybe some naive expectations on my own part, and it will probably be blatantly obvious in my presentation.

Our needs for the canyon project are, currently, we have about 500 Megawatts of resource capability on our system, some of these are jointly owned projects with some of the other cities in the Southern California Region. Most of that is a 24-hour must take base load capacity, so we really have a peaking requirement. During the summer, we peak between 550 and 590, so we have a deficiency of about 50 to 90 Megawatts, depending on how hot it is. In addition to that, we have a planning reserve margin, a resource adequacy margin, that we must maintain, so that is going to ask for an additional 80-100 Megawatts.

There is another issue there that I know we have talked about, the local capacity requirement that was discussed earlier, that the ISO has for the Basin. The load serving entities such as Anaheim and some of the other cities have to share that obligation. Currently, we have a need for 300 Megawatts of LCR requirements. Most of our generation is outside the state, so we have very little in terms of local capacity requirements. So this one of the bigger reasons for why we needed the facility. In addition, we do have some wind and hydro facility renewables that we are part project participants in, so having a quick start capability was another reason for our needs. Just briefly, it is a 200 Megawatt facility to 4 LM 6000 simple cycle facilities. We actually have designed for a NO_x target of 2.3, it is a little bit lower than the current 2.5, and we are also using reclaimed water for our operational needs.

I just wanted to kind of walk you through what our experience has been to date. When we first filed our application, we based it on the 1309.1 section in terms of how to calculate what ERCs we actually needed. We went through a process of determining that, based on the rules that Mohsen talked about earlier, that we probably need about 500 hours of operations, that translated to about 48 pounds per day for ERCs. Based on the rules at the time, the cost for the ERCs were about $92,000 per ton. We would have written the check for about $5 million, which would have gone to the AQMD to help them find other programs for remediation. We filed our application in December of 2007. Now, here is where my naivety comes into play, we had every expectation that, not that we were presuming the license was a fete accompli, we just thought that it was a pretty standard program, pretty standard generation, we thought based on our best knowledge and backing into how long the process would take, that we would actually have the project commercially operational summer of 2010, those were our expectations. So when the Judge's Order came out to -- in July that we talked about earlier -- we had to scramble to figure out, okay, well, we might not be able to rely on 1309.1, we had meetings with the AQMD to talk about, well, what possible solutions do we have for this. We did a little bit of research. Now, I know that we talked earlier about Section 1304 for repowering, my understanding is that there was another provision within this, that if you were emitting less than four tons, you could file under that application, or that rule, and you would be exempt from having to require the ERCs. So based on that information, we sort of backed into, well, if you could not emit more than four tons a year, what would your operational level have to be to be able to qualify for 1304? So we went through quite a bit of revising our application, which took some time for us to do. And so we had to file a revised application to the AQMD in September of '08, so we had to completely alter a lot of the tables that go into the application, so we thought we were good for that. Then, when the clarification order came out in November, that excluded our ability to qualify even under 1304, so our only solution at this point, bearing in mind all along that we wanted to stay on schedule, or keep the project moving along, as opposed to waiting for clarification of how this was all going to play out, we entered into the market to procure the ERCs directly. Now, just based on our own experience, I did want to say that, while Mohsen's graph showed there were 1,000 ERCs available, our experience was that, well, you have got two markets there, you have got one for the inland area, and then you have one for the coastal -- we were in the coastal market. So we worked feverishly with trying to get the credits, only to find that the actuality was, when we entered the market to actually buy the credits, there was only one provider, one seller, who had enough credits for us to purchase to get back on schedule. Now, that is not 1,000 Megawatts that was on the table, just to let you know anecdotally, the first shot was that this seller had, I think, about 28 pounds available and we needed 48. So we procured those, we had with one seller and I think, obvious to him, that he knew what we were doing, we ended up paying $310,000 a pound for that, rather than the $92 that we would have gotten under the old provision. So we really did not have any negotiation capability in terms of the price. You have got one seller providing something, you know, if you walk into a car dealer and there is only one car there, and you really needed to drive it, then you really do not have much leverage in terms of discussing price. And considering that we needed to continue our process going, we ended up having to procure it, and the other 20 became available at a later time. But the bottom line is we ended spending about $15.5 million for the credits. Now, to a lot of you, that may not sound like a lot of money, but for the City, you know, our revenue requirement is $270 million a year, so an extra $10 million added to the project, I had a hard time going up to the 11th floor to explain that to my boss, but we still wanted to make sure that the project floated and continued on. So then, based on the 48, that sort of gives you an indication of what we calculated to come up with the 48 that we needed, so we were back to operating over 4,000 hours.

So the final application we submitted, it was almost a year later from the initial application because we had to go back once again to revise all the tables that go into the application the AQMD needs to do their work. So anyway, just to give you kind of from our perspective how this whole thing plays out, as I said, our original application was filed in December, we got data adequacy in three months, the AQMD, because of the delay in the process, we actually ended up getting our PVOC in February of '09, so this whole litigation process actually cost Anaheim at least six months in terms of revising its application and being able to stay on schedule. We had a joint workshop in May of '09. I forgot to mention, when the Energy Commission issues its preliminary staff assessment -- and I have the second column in there as sort of the theoretical timeline that is provided and, again, this is our inexperience with the process by actually believing that those dates would actually occur. Most of you have probably had more experience with licensing processes and understand that there is always, you know, the optimal versus what actually happens. So we were still trying to stay on schedule with the process. So as we kind of go down the table, we are at a point right now where we are still waiting for the Energy Commission's Final Staff Assessment, that would be the last regulatory piece that would get us into the licensing process. We are hopeful that the October date that we were given is going to work. And I think, based on that scenario of trying to get back on schedule, when we went through this process of the delays of getting the actual ERCs, it became very clear that the summer of 2010 was highly ambitious, so we were hoping that the summer of '11 would work. Anaheim definitely needs to have the capacity available. At this point, I am not quite sure if we are going to be able to make the summer, depending upon, you know, if there are further delays. We have kind of walked through starting with construction and working ourselves backwards where different dates had to fall in play for us to stay to that schedule.

So this is just Anaheim's unique experience that occurred. So my apologies to Mohsen, he has already addressed this several times, but obviously I put my presentation together in advance of knowing what he was going to say. But I understand the rules. We were suggesting, and I guess this has already been commented on, for a peaking facility, I guess the rules are the rules, but I think our recommendations fall in line with what some of the other speakers were saying. We ended up buying theoretically for the entire 4,300 hours. Our practical use for the facility during a 20-year forecast was closer to 2,000 in terms of what we would actually operate, but because of the way the rules are set up, we definitely ended up having to procure what would effectively play out to 4,300. So our recommendation, obviously, is in line with what some of the other folks have brought up. If we had a magic wand to wave the rules, what would make sense? For a peaking facility, some of the experiences here that we thought out were, you know, you have a limitation for how many hours during the month that you get permitted for, and I understand that is our number that we put in there, so what we are thinking is would it make more sense for a peaker to look at it on an annual perspective, rather than the worst month scenario. And the reason for that, obviously, is during the non-summer months, there is really not a need to run a peaking facility, at least from our perspective, because we have so much base load capacity, we have more than we need for nine months out of the year. So we thought, well, if you had the ability to calculate this on an annual basis, it gives you a couple of advantages. One is, if you could actually bank those for the entire year, so that in any give month, if you need to use more operating hours to be able to meet your load for extenuating circumstances, is essentially it would be, well, I do not need to run them in March, how about if I have those concentrated in the summer months? So that was some of our thinking.

The other thing we thought of for a multiple facility, multiple unit facility, each one of the ERC credits is based on a per turbine, and we were wondering would it help if you applied it for the entire facility. And the thought process was, well, supposing that you ran one turbine for 90 hours that you were limited to for the month, and now you have to go to another turbine in order to meet your load, and what happens if that turbine breaks and is unavailable? It just precludes you from being able to rely on a different turbine. So we thought that if you looked at it from a facility basis versus a per turbine basis, and if you looked at it from across the entire year, for peaking facilities, it might help in that it would give the operator a little bit more flexibility. But notwithstanding the rules, that was just our proposal.

Just to wrap things up really quick, I had a couple of questions, and this is again based on our inexperience with the process. We were not quite sure what the rationale for the 1.2 multiplier was after you go through the process of calculating how many hours you are going to operate. The other questions we had were, in terms of this particular process, do you need to demonstrate having secured your credits so early in the process? That is kind of an investment that, if you are not going to be able to do anything other than buying out at the market, that is kind of an investment that you have to make way early in the process. And, of course, without those, I think -- my understanding was the PDOC is not issuing until you procure those, and that is another meter that starts the process.

And then, finally, recognizing where I am in my venue here, as far as the licensing process is, and this is again our inexperience with the process, we were trying to go backwards with where we thought we needed the project to be online, and we were somewhat relying on the Energy Commission's website to say, well, this is how much time it takes to do this, this is how much time to get to this point. Our process was that, you know, I do not know if this is the case for other developers, you know, we had to have a contract with GE for the turbines. We had to procure those in advance because part of the requirements for the PDOC is you have to have a vendor guarantee for the emissions, and a vendor is not going to give you that until you sign a contract. So that was one of our dilemmas, was that all right, we have already got the turbines, they are already being built. The other process for cities is that a lot of things that we do are driven by putting out requests for proposals to take bids for construction. Those have to be done in advance and they have to be done under a City procurement rule. So we have actually hired EPC contractors in anticipation that we would be available to go commercial in '11, and, again, Commissioner, I am not trying to preclude the process, or presume that the license is a fete accompli, but basically the question is a rhetorical one, you know, how do utilities have to plan for how far in advance they need to do things in order to go through the process? So it was more of a rhetorical question, not a criticism, just our experience has kind of got us to the point where we are just holding several people at bay waiting for the process to continue, recognizing that we had to do that in order to stay the schedule.

COMMISSIONER BYRON: Well, it is very informative, Mr. Sciortino, and I assure you, we will be making our decision based upon the evidentiary record, not what you present here today.

MR. SCIORTINO: Of course.

COMMISSIONER BYRON: So this is very helpful. And your questions, I do not know, Commissioner, how many developers should we let come up and underscore for Mr. Sciortino that it is actually worse than he thinks?

VICE CHAIR BOYD: I was not going to say anything like that. And I was going to try to make him feel better, though, that he is not alone.

COMMISSIONER BYRON: Yes --

VICE CHAIR BOYD: My own notes say, you know, good points -- when is the last time we looked at the whole system rather than our piece of it?

COMMISSIONER BYRON: Yeah.

MR. SCIORTINO: That is just our experience, sir. I just wanted to just kind of tell you how it happened for us, that it is unfortunate that we were right in the middle of the perfect storm with the lawsuit and that is probably the main drive for us to figure out, well, what we needed to do to kind of figure out, well, where do we get the credits? And I just want to reiterate, the market is not really out there, at least at the time we went to actually get something that made sense.

COMMISSIONER BYRON: I suspect there are many here that could tell you they are also involved in this perfect storm, and could underscore some of the same observations that you had. I do not want to preclude them from speaking, but if it is alright with you, in the interest of time, I am going to suggest that we press on.

MR. SCIORTINO: Of course.

COMMISSIONER BYRON: Thank you very much for your comments. In fact, I think you are on our next panel, as well. And if I could ask, it looks as though we have got three of the Energy Commission staff moderating this, Dr. Jaske, Mr. Layton, and Mr. Vidaver. And the panelists, I think, are you going to have them all come forward to the table? All right, let's do this as quickly as we can, then, so we can get to the content and I will allow my moderators to do the introductions. And we have some new panelists who have not spoken today, but if you would all just come forward and grab a seat? Do you have nametags there, too? Is that right? Dr. Jaske, how do you plan to conduct your panel?

DR. JASKE: We are --

COMMISSIONER BYRON: Go ahead and speak to the panelists. I do not want you to have to turn towards me.

DR. JASKE: I think we are going to go through the questions. We may decide to pare down some of the questions because they are -- they have been covered sufficiently, and like we have in some other workshops along this topic, we may point to a particular person to lead off, and then ask the other panelists to sort of react to that opening comment.

MR. VIDAVER: Do we need the panelists introduced at this point? Or do we all sort of know who we are by now?

COMMISSIONER BYRON: No, I think that would be great. Please, you can introduce them, or have them go around.

MR. CARROLL: Mike Carroll with Latham & Watkins.

MR. KOSTRZEWA: Larry Kostrzewa, Edison Mission Energy.

MR. SCIORTINO: Steve Sciortino, City of Anaheim.

MR. NAZEMI: Mohsen Nazemi, South Coast.

MR. MINICK: Mark Minick, Southern California Edison.

MR. JOHNSON: Keith Johnson, California ISO.

MR. MOORE: Bruce Moore, LA Department of Water and Power.

MR. VIDAVER: The first question in the panel topics that are appended to the agenda deals with South Coast rules being based on worst month scenarios, and asks for a comparison of the rules with those in other districts, and alternatives suggested by parties. Parties have suggested numerous alternatives it the past couple of hours and, in the interest of saving time, perhaps we can stipulate that, if parties want to comment on anything they heard, speak to anything that they have not heard suggested in the last couple of hours, they may do so in written comments, unless anyone would like to take on Mr. Nazemi again right now. So if you have comments on the presentations that you have seen, and the recommendations for rule revision, etc., please provide them in written comments, and any additional recommendations you may have, etc. And then we will probably at some point turn them over to Mr. Nazemi and talk to him about them, and you will get the chance to read our summary some time in December of January, before we officially release the document. Do you want to do this in rotation? Or do you want me to --

DR. JASKE: Well, I think that the Question 2 has obviously been provoked by the whole discussion today and Mr. Nazemi said it well, that the district is now looking to the state to figure out how to somehow or other pull together something that serves the function of 1309.1 for new power plants. So maybe one question is, and ever since the State Court first decision was issued in July, there has been all kinds of discussions about this issue, so the question is, is there a forum that already exists, that can take on this issue? Or is there something new that needs to be formed to really bring focus to it? So perhaps, Mr. Nazemi, if you could answer that question and others react to that?

MR. NAZEMI: Sure. I think from South Coast's perspective, the forum should consist of the agencies that have the expertise in dealing with the issues, such as the energy demand forecasts, transmission line capability, local reliability. Again, you heard a lot about inertia and other factors that are unique to the utility industry, and agencies that have jurisdiction over there, so I think you are really asking whether there are the experts available to do this, and the answer is yes; whether there is a forum that is an official forum, I guess I cannot say that I am aware of one. But I think the expertise relies on it, the Energy Commission relies on it, and the System Operators, the utilities, the Public Utilities Commissions, the agency that approves these contracts, so they all have their own unique expertise and they are all part of this equation. But South Coast clearly is -- our expertise is in air quality and not in transmission line and renewable resources and things like that, so I do not think it would be fair for us to carry this load. I think it would be appropriate that other agencies who are the experts do it, and if they need help from us relative to air quality, we will be more than happy to participate.

MR. SCIORTINO: Dr. Jaske, doesn't the Energy Commission have a working paper that talks about gas-fired generation for the state required due to a variety of reasons? One is operational, some of it is in support of the renewables that have to come in play, and I think that was a joint effort. As an outside contractor, I think that should be brought in to help you with that. But I think it has been, in terms of working with the ISO and some other folks that have some input into it, I kind of thought that that was a nice starting point, by identifying, well, what is the potential for gas generation required? And I think, if I understood that study, they were looking at it in a more microcosm perspective like, okay, well, let's look at it in terms of SP-15 requirements, and break it down in more granularity. But, to me, it seemed like, well, that is a very good place to start from because it identifies a lot of the issues that we talked about this morning for regulating, for intermittent resources, and where it needed to be built, and I thought, well, if you could just take that document and carry it a step forward and identify, "Well, how would these guys actually operate under that scenario?" You could actually calculate, well, how many emissions would be required based on that? I guess my concern is that, you know, if you have any kind of an allocation process, it is sort of like the first guys that get to the trough actually will get the ERC credits in the future, but what do you do for folks five years from now who need to develop something? So I thought that document that the Energy Commission has sponsored was a very good working -- a very good place to start.

DR. JASKE: Well, I think maybe it is a start, but as Mr. Minick and other representatives of the ISO said, there is probably a long ways to go to really wrap it all together and have it be sufficiently tight, that everyone could buy into it. Other reaction?

MR. CARROLL: I would just say I would caution against getting too bogged down in finding out exactly how many Megawatts we need before we proceed to figure out what the solutions for the emission offset problems are because I do not think we need to know the former with an extremely high level of precision in order to recognize that we have got a problem. So we do not know exactly how many Megawatts we need, perhaps, but we know that we need some, and at this point, with a couple of limited exceptions, we cannot permit any. So I get a little bit nervous that we are going to get too bogged down in refining the model, and come to some conclusion on exactly how many Megawatts we need, and then once we have got that behind us, then we will turn to, okay, then how many offsets do we need and how are we going to generate those. I do not think we need to take these issues in sequence. I think they are both important, but I think we can move forward on the emission offset solution in parallel with the planning that is underway. And to some extent, you know, there is this what I view as sort of an irrational concern about, you know, over-building, or having too many offsets available in the market that, you know, if we make offsets available, then we will have all these power plants built that we will not need, and they will just operate all the time and emit whether there is demand for the electricity or not. Well, you know, the extent to which the power plants operate is the extent to which there is demand for the electricity, and the more -- so if there is no demand for the electricity, then the plants will not run. And if we [quote unquote] "build too many" new power plants, you know, the worst thing that happens is more and more of the old power plants get displaced. So this concern that we have seen on the part of a number of decision makers about, you know, "If you make too many offsets available, we are going to have an over-built situation, and that is bad." I frankly do not understand that. And so I would just say let's get focused on the emission offset problem and solutions to that problem while, at the same time, you know, doing the planning work that you all undertake to determine what the future needs of the area are.

MR. VIDAVER: Do you see there being some -- do we have a priority reserve mechanism that might set a number of offsets, but would be made available? Or do you see something along the lines of long-term contracts for resources being authorized by, for example, the CPUC, and whatever was awarded in that contract would be given a number of offsets that it needed? Or, you mentioned something about a market solution to this and I am trying to -- what picture do you have in your mind of how offsets are made available, aside from the numerous revisions you suggested?

MR. CARROLL: Well, I do not think you need to have -- and, in fact, I do not think it is a good idea to have a single source of offsets. You know, I think that we should look to ways to make the private market more robust. I think it should be not so onerous for private parties to generate offsets and make those available in the private market. I think we need to tap into the South Coast Internal Emission Offset Accounts, notwithstanding some current hesitancy that they might have to delve back into that for the power sector. I think we need to because that is a viable pool of offsets that should be made available to the power sector, beyond what current rules and legislation will allow. So, you know, like any market, having a sole source situation is not good. And so I think we need to look at a variety of opportunities and markets, whether they be agency-based, or private markets, so that we have got various opportunities for these sources to satisfy their emission offset requirements.

MR. KOSTRZEWA: I would recommend not tying it to what he is saying, a power contract or not. You know, in the current market that we have for power in Southern California, or in California, it does not make sense to build a power plant without a power contract, but it is the goal of many policy makers to create a robust competitive market like you have in PJM, where utilities do not have to sign long term power contracts in order to get facilities built, that really the market determines what is the right thing to do. And we should not develop a mechanism for how things are today because how things are today are transitional. And I definitely want to emphasize what Mike said about how much power plants operate. We cannot force electricity into the grid that the grid will not use, and so new power plants, well, the most competitive power plants are the ones that run. And if non-competitive power plants cannot compete, then they will shut down. It is how things work in the east, and it has been quite effective at bringing a lot of new generation capacity on throughout PJM.

VICE CHAIR BOYD: This forces me to ask a question of anybody. Since this is [quote] "allegedly an evolving market," do you think that there is a level playing field now in existence in the California market for the IOUs and independent power producers, particularly with the recent advent of so much utility owned generation?

MR. KOSTRZEWA: That is a third there. I think the CEC is -- or maybe it is CAISO that puts out a study every year that shows their calculation of whether new generation could afford to build in the market as it exists. And the energy market certainly does not support constructing any new generation, and nor does it in the east, and so, really, it is the resource adequacy market that provides the famous missing money. And that missing money really comes from the desire for more reliability than would be truly economic. And with resource adequacy payments where they are, there is not enough money to support the generation. And the caps on those prices may keep that from happening.

MR. CARROLL: I am going to deflect a little bit your question of whether or not it is a level playing field, but what I can say is, for the independent power producers, it is becoming a playing field that is not very attractive to enter into, and some of this was mentioned by other speakers, but when you couple the money required to but the security emission offsets, as early in the process as the CEC staff would like you to acquire them, with the money that is required to secure your power purchase agreement with the utility, with the money that is now required to secure your electric system upgrades under the new cluster approach of the ISO, and those are almost three certainties, and on top of that, if you feel for whatever reason you need to move forward with your equipment and your EPC contractor, the amount of money that is required to be laid down very very early in the process, before we could have any idea as to whether or not you are going to have a project or not, is becoming a huge deterrent for the companies that I represent, and are looking at it and just saying, "This just doesn't work. We do not have and we cannot get financing of that magnitude for a project that is so speculative." And we are talking about all of those obligations coming, you know, early in the process, certainly pre-PSA. So whether it is a level playing field or not, it is one that is becoming very unattractive to the independent power producers and very difficult, I think, on a going forward basis for us to attract that sort of investment.

VICE CHAIR BOYD: Thank you.

DR. JASKE: The last sentence of that question raises the whole question, assuming that there is some amount or aggregate amount of offsets, credits that are available, how they might be allocated is one word, or some other word, how will multiple power plants end up obtaining some presumably limited amount? Any thoughts from you about how to deal with that? First come, first served? Or what?

MR. KOSTRZEWA: Well, I would say first come, first served, but maybe that trivializes the complexity and difficulty and expense that Mike is talking about. It is very very costly to build a power plant and so it is highly unlikely that more people will seek to be served than the market will support. But I think it does make an awful lot of sense to have a pool of offsets in one place accessible at a known price, so that in order to create at least a competitive market of new generation options, I use the era word, the shovel-ready projects, so that when a utility seeks new generation capacity through a request for offers, maybe there are three or four or five projects that are permitted on the basis that they will have access to this pool when and if they build. And that way, the utility gets to choose between power plants that have gone through the process and are real, but without that 50 to 80, or however many million dollars speculative up front bet we would have to get through the permitting process without such a pool.

MR. VIDAVER: So it sounds like your solution is slightly larger than Mr. Carroll's, maybe. You are allowing for a more administrative socialist solution.

MR. KOSTRZEWA: Well, I would like to have a competitive solution on top of that; I think if it was a lot easier to create emission offsets, we would be out doing that, and if we could not generate enough offsets on our own, it would be nice to have the pool to fall back on.

MR. SCIORTINO: Dave, can I just ask one question? And I know this process is targeted more for the investor-owns, but I am curious to how the developers would perceive if it was a first come, first served, they would gobble them all up, and then at some point LADWP or some of the other cities who do not have that same process, but come along three years from now, or five years from now, there is no ERCs to be had, but yet we have the same obligations to provide the same reliability criteria that the investor owns do.

MR. KOSTRZEWA: Well, as a developer, again, I do not think that we would be gobbling them up without building the plants, and if we built the plants, then there would be plenty of capacity in the market.

MR. SCIORTINO: Well, I am just saying that the first come, first serve, I always get a little bit nervous. I know when 1309 came out and there was -- I think it was a limit of 20 -- 2,000 Megawatts, or something to that effect, and it was like, well, the first 2,000 to come to play, they get the credits, and then three years from now, Anaheim or LA comes in and says, "Hey, we have some deficiencies that we need;" we are not in the same position where we could actually build our own. We do not need to go through the development process that Edison might have to.

MR. KOSTRZEWA: I completely agree that a cap on the number of Megawatts would be not beneficial.

MR. CARROLL: But that cap, it was 2,700 Megawatts, that was not a function of the quantity of offsets available, that was, again, the concern on the part of the governing board of South Coast that there would be too many power plants built if they made an unlimited amount of offsets available. So that was their attempt to --

MR. SCIORTINO: Well, I understand that, but conceptually what I am getting at is, what if there is a limit on the number of ERCs that are available for allocation? And if you go to this first come, first served, and it is the developers for Edison who has requirements, then if those allocations are used up -- and that is why I kind of like this long term planning thing where you are looking toward the future in terms of, well, what is the overall over the next 20 years. I know you do not like the idea, but from a scientific standpoint, you know, it is not just the investor owns who have facilities in South Coast. I mean, Edison is not the only player here.

MR. CARROLL: Do not get me wrong, I am not saying that we do not need to undertake the long term planning, I think we should, but I just do not think we need to wait to find out what the offset solution is until that long term planning is completed, especially since, you know, what I am hearing is that is going to take months, if not years, to do that. And frankly, I think we may be getting a little too bogged down in an issue that we need not because I think if we start to implement some of the solutions that have been proposed, there are going to be plenty of offsets available for all the projects they can otherwise get permitted and get financed, and move forward. So I do not -- let's not get too bogged down in "what are we going to do with this limited pool of offsets," to the exclusion of thinking broadly about how do we generate enough offsets for everybody. Because if you look at those pie charts, there are a lot of emissions out there, we just need to figure out how to tap into those to generate credits for stationary sources.

MR. KOSTRZEWA: And, of course, figuring out how many Megawatts are needed, and that study is obsolete the day it is printed because the world changes.

MR. VIDAVER: Looking at Mr. Nazemi to see how he is reacting to the notion that a New Source Review Working Group can come to a consensus and lead the District down a path to a larger number of offsets without too much difficulty.

MR. NAZEMI: Well, I think I am kind of having like a déjà vu where our governing board was amending our rules to allow the use of credits from our bank by the power plants and, in their infinite wisdom, they came up with, well, has to be a viable project. So one project proponent can come in and put a huge hold on all the credits that are in the bank and not allow competitors to move forward, so the idea of first come, first serve from the point of view that, you know, the moment you put in your application, you are the first one in line, was not appealing to us. So we thought that viability means you have to demonstrate that you are going through this CEC licensing process, and at least meet their requirements. It has to demonstrate that you are either, like the City of Anaheim, or LADWP, that your local municipality is serving your native load, or if you are selling into the grid, that you have acquired a contract that shows that you are serious about providing this power into the grid for California residents. And the limitation, as Mr. Carroll indicated, was not a limitation on the amount of offsets, it was based on, again, at the time we were relying on the projections that were given by the state agencies, and they were looking at some 2,500, maybe 3,000 Megawatts of increased generation that is needed to prevent rolling blackouts in one in 10 situations, so that limitation was put on so that, if in fact things change, and it was determined that, whoa, this was the wrong estimate, we needed really 5,000, that there was a provision that you can always go back to the governing board and demonstrate that, you know, there was a need for additional new generation. So that is the answer to the first part of the question, you know, how do we go about us doing this. But, again, we are not in that business anymore, so it is something that you all need to participate in and decide how best to do this. As far as suggestions that are being discussed, and New Source Review changes, again, I caution that ideas sound very reasonable when you talk about it, but again, we are dealing with mandates in the federal and state and local requirements that needs to undergo rulemaking and I know we have mentioned numerous times today SB 288, and I am not sure, Commissioners, if you are familiar with what SB 288 is or not, but it was an attempt by State of California to stop rollbacks of federal administration in terms of New Source Review when the federal law was being amended, to say that you cannot make your New Source Review any less stringent than what it was in effect December of 2002, which was the day before the federal law went into effect. So any change that we make to our New Source Review Rules, since SB 288 was passed, needs to undergo scrutiny, to make a determination that it is not making rules less stringent. Now, that is not to say we cannot make any changes, but it is -- I just do not want to leave you with the idea that, you know, again, we are sitting there not moving and making a change to fix the problem, and if we did that, that would be the end of it. In fact, one of the plaintiffs actually filed a petition with the California Air Resources Board when we did the adoption of Rule 1315, and amendments to 1309.1, that we violated SB 288, and that took ARB a couple of years before they made a decision that we did not. So I do not want to lead you on the rosy path that, as soon as you make a change to New Source Review, everything is fixed.

MR. VIDAVER: Thank you. Okay, let's see if we can get the gentleman from AES leaping out of his chair. Let's talk about 1304 exemptions. I am not exactly sure where to start, but there are those who believe that making 1304 exemptions available to owners of existing power plants, but not providing such easy access to offsets for Greenfield facilities, has a number of implications, that perhaps as fundamentally exist are downright unfair, might limit competition in RFOs, there is -- that it really would not matter anyway because Brownfield sites have such an inherent advantage over Greenfield sites that they do not really need the additional advantage of a 1304 exemption. I do not really know where to start and I am sort of tempted to go back to Mr. Nazemi and ask if there is the difficulties in a mechanism where the offsets associated with a Brownfield site would somehow be released from the site itself and allocated sort of in some administrative sense to the people eligible for a contract, or whatever requirements you had for eligibility for priority reserve. Could 1304 -- the offsets under 1304 exemptions somehow be channeled through that process and not create too many problems?

MR. NAZEMI: Mr. Vidaver, I think it would help if I just mention that 1304 exemption is not just for power plants. Power plants is a very small portion of 1304 exemptions. And 1304 was not a provision in our rules that started with power plants. There may be a few, three or four different types of exemptions under 1304, but in general the power plant exemption that comes under 1304 was in our view an environmentally beneficial exemption. Again, you are taking an old utility boiler, replacing it with combined cycle, or advanced technology gas turbine. It did not take a rocket scientist to typically calculate that the emissions are going to go down because of the increased efficiency and the better technology for controlling emissions on these types of operations. There does not seem to be -- and then the other process that has been and still is available under our rules is that any industry, not just power plants, that needs to build new Greenfield or Brownfield facilities, that they need to comply with the offsets requirement and the ability to obtain the credits in the market is a challenge, it is not just for power plants. As we saw during the moratorium, every facility -- a hospital had to pay millions of dollars to get offsets, so if you can imagine there are industries that are not exempt under 1304 or 1309.1 today, and they have to deal with the offset issue. What becomes unique for power plants is, because they typically are a large source of combustion of natural gas, which is a clean fuel technically speaking, and when you look at the emissions of the stack, I mean, we pushed emission limits down to 2 ppm or less for pollutants, almost to the point where it is hard to measure with existing instruments, it is not that they are dirty per pound of or cubic foot of gas that they burn, it is just that because of the magnitude of the amount of power that they need to generate, they burn a lot of gas and that results in a lot of emissions. Now, we are not a proponent of power plants, but when we look at the alternatives, the distributed generation was mentioned today by Commissioners and other parties here, when you look at what the emission impacts are from distributed generation versus central power generation, I think unless you are talking about fuel cell or some very clean micro-turbines, you can easily see that the emissions are three or four times higher per megawatt, again of NO_x that is generated from distributed generation, that is typically known as internal combustion engine, even with the best controls they can put on it compared to a power plant. So I think that it needs to be put in perspective, that is part of what our permitting process does, we look at what is BACT and what is layer, and those achievable emission rates and best available control technology, and would we implement it in that fashion. So the problem with the power plant that can be unique was that there was not enough in the open market that they could buy, and because they needed large chunks of credits, as you heard from the City of Anaheim, you know, there is not really many single holders that have that many credits in their position. So unless you can work out through the brokers and buy two pounds here and 10 pounds there, and five pounds over there, and get it all from those that are willing to sell, then you cannot get it. So I think the power plants brought this offset issue to maybe more high a tension, but it is -- the process is there, you generate ERCs and you sell it in the market to anybody that wants to use it. I think to some extent we are getting to a point where, when you are paying $350,000 per pound per hour of PM-10, you would have to take a step back and see was that really the intent of the Clean Air Act and Congress that you really, instead of putting your money into the technology, and if you look at a plant, at a 500 Megawatt plant that spends maybe $15-20 million on air pollution control technology, if they spend $200 or $150 million on offsets, wouldn't that money be better spent somewhere else? And those are part of the reasons why we felt that it was -- if the power was needed, it was appropriate to use the credits that we have, provided we can charge the power plants and use that money to invest in emission reductions, which is ultimately our goal, to clean the air. I do not know if that gave an answer to your question. That is part of the thought process.

MR. VIDAVER: I am trying to imagine if you have a power plant that needs 600 pounds of ERCs and those are not available in the market, so you establish you have a Brownfield site that has -- that is entitled to those 600 pounds under 1304, and you have another -- an Edison Mission plant that either has to go into the market where it cannot get the credits because they are just simply not available, so the alternative is some kind of District bank that is set up and methods are devised to allocate that, and you turn that over to Mr. Kostrzewa, if there is a mechanism by which the plant that he builds is designed to replace an existing steam turbine, that then would shut down because the Edison Mission plant has been given a contract, or has otherwise been designated as replacing the existing facility, that sounds like kind of a desirable outcome.

MR. NAZEMI: It is from a regional standpoint, but, again, you know, we are talking about what is required under existing federal, state and local laws. And new facilities such as the one that Mission Energies is proposing to build is not at the same location as a facility that may be in AES' site. So we are looking at a brand new facility that meets the offsets emissions, you are looking at an existing facility that is ultimately shutting down a generating credits, so you need to follow the rules that are in the books. Unless you want to change those rules, and it is a smooth process without litigation and anything else, you are stuck with what is available today. And I do not think that there is -- I do not think that is the ultimate solution because, if you think about it, you are asking one company who cannot get credits out in the open market from maybe 20 holders who are not willing to sell their credits, to now go to a single credit holder, and if you think that single credit holder is going to give a really good deal to this company, I think you are maybe having a high optimistic view of this.

MR. VIDAVER: I thought I was setting up the District as being the single credit holder, maybe that was not -- maybe I am not making myself perfectly clear.

MR. NAZEMI: Well, we -- I think there are companies such as AES, or any other company who has equipment that are permitted and eventually may shut down, that have the right to at this time come to the District and claim those credits for their own. We only have credits in our bank that are what we call "orphan shutdowns" that the companies who have those equipment and they do not claim them. So if you are talking about making those credits available, again, we are kind of like going back in a circle. We tried to do that, but it did not work.

MR. KOSTRZEWA: Personally, I think the electric utility steam boiler exemption replacement exemption probably dates to when the electric utilities owned the steam boilers. And for municipal utilities and for LADWP, it still makes a lot of sense because the benefit of that exemption flows directly to the ratepayers. Now that a good number of the electric utility steam boilers are not owned by electric utilities, it definitely skews the marketplace, and you know, maybe when the emission offsets were a few hundred or a few thousand dollars a pound, that was not a big issue. But now that offsets can exceed 10 percent of the cost of building the power plant, those with free offsets are definitely in a different competitive position than those that have to buy them, or create them. And I find it interesting, as was pointed out earlier, of the four power contracts that SCE signed in their solicitations, only one of them was from a repowering facility. And, you know, if we tilt that competitive marketplace, do those competitive options, those competitive options would just probably disappear. I do not know what the solution is from that, I certainly would not want to deprive any of the existing plant owners of their property rights, which, as Mohsen says, they are entitled to shut down credits. And there is no way that if one of my plants wins a power contract that somebody can force somebody else, another company, to shut down. That just would not be Constitutional. So I am not sure how we solve that. But a level playing field would be very nice.

MR. VIDAVER: Thank you.

COMMISSIONER BYRON: Are we going to hear from any of those folks on the other side of the podium?

DR. JASKE: Yeah, I think I am going to do that right now and shift us to a portion of Question 4, and that is the whole notion of squeezing more capacity into limited air credits by use limited power plants. We talked a good bit with the example of Mr. Sciortino's Anaheim plant about, you know, how many hours he was being passed pay-for through ERCs versus how much he expected that plant to run, but there is a whole different perspective which is the ISO's Resource Adequacy process, you know, backstopped by PUC decisions that is sort of pushing in the completely opposite direction, wanting more plants to be, in effect, 8,760 available around the clock. So perhaps Mr. Johnson, I would ask that you reflect on ISO's perspective about, you know, is a future with a lot of use limited power plants where the ISO wants us to go?

MR. JOHNSON: Thanks, Mike. Well, a few comments. You know, the ISO it being charged with operating the grid essentially, we are charged with taking the resources that are procured through the Resource Adequacy Program, and that is what we operate the system with. So obviously, we would prefer that we had plants available 24/7, you know, base load type plants, or at least plants that are available in the sense that they are physically available and capable of operating 365 days a year. Of course, that is not the case. We have a variety of different resources that the ISO uses to operate the grid. As you all probably know, if you look at a load duration curve, you know, one might argue that, given the shape of the curve, that there is really only a certain number of hours that we really need this peaking facility, you know, the peaking ability to generate on-peak. One of the real challenges for the ISO, though, is that we do not know exactly when that peak is going to occur, and then, from the operator's perspective, throughout the year at any give time, there will be either clearances that are required, or outages, for example -- forced outages. So it is really a challenge to try to operate the grid with a lot of use limited resources, with limited numbers of hours that they can run. We are currently doing that. We do have a number of use limited resources in the fleet now. And so that is something we have learned to adapt to. I guess another comment I would have about the resource adequacy program, the way it is constructed, particularly the piece from the CPUC, they have this concept of what they call Resource Adequacy categories, and they are essentially four buckets. And if you are load serving entity, and you have a portfolio that you have to fill out for RA, the PUC's counting rules only allow a certain percentage of the resources to be of the bearing types. Really what it is trying to do is to try to mimic that load duration curve. So, for example, the fourth category is Category 4, it is really resources that can run 365 days a year. In your portfolio, you could comprise that 100 percent of those. As it moves up the steps, three, two and one, there are resources that are not capable of running that many hours. So, for example, at the highest level, so-called Category 1, if you have a resource that you want to have qualified as a Resource Adequacy resource, it needs to run a combined total of 210 hours per year through the months of May through September. So what I am getting at is, and I know one of the questions in looking at the materials for this workshop was, would the RA program -- does it put any parameters, if you will, around what we might need to be cognizant of, and we are thinking about having a lot more resources be use limited or limited run time. And I think the answer is yes, to some extent. Some of the load serving entities might find themselves having difficulty making portfolios that have a sufficient mix of these category 1, 2, 3, and 4 resources, because you cannot submit an RA showing that it is composed entirely of Category 1 resources -- remember, those are the ones with very limited run hours -- you have to have a mix, at the very least, you could have all number 4, but you certainly cannot have it all use limited. And so I hope that helps you at least understand kind of how the RA program works, and how the use limitation, in effect, is working within the RA Program. One other thing that Mike has mentioned, that I just mentioned about availability, the 8,760 hours, we do have a new aspect that we have just implemented in our market called the Standard Capacity Product. We have crafted a notion of what we call availability. This is really physical availability of plants, in other words, what it measures is our resources on forced outages, and if they are, how does that compare with the fleet of resources. And what we do is we look at the last three years of historical performance of resources and we look at their forced outage rate, and that establishes a standard. And so, for example, use limited resources have an ability -- what we do to look at those is, we look at each month there is a standard each month and we make an allowance for use limited resources such that, if they have at least fulfilled their commitment during the month, in other words, they have run for a certain number of hours, provided a certain amount of Megawatt hours of energy, we consider that they are [quote unquote] "100 percent available." So I guess where I am going with this discussion is to share with you that we certainly would like resources to be physically available 8,760 hours a year, we recognize that there are forced outages, so that is not held against resources from an RA perspective, or an availability perspective, and then we also recognize that there are resources that do not run or cannot run for 8,760, and the program does not penalize them for their legitimate use limitations that have been factored in to the RA program.

DR. JASKE: So are there reactions to what Mr. Johnson said?

MR. MINICK: Possibly just a clarification. Everybody is talking about fossil peakers. Some of these used from the resources might actually be hydro plants because they have not got sufficient water to run every hour of the month, so let's not say that this Resource Adequacy counting is just trying to pick on fossil plants, it is any plant that might have some ability not to run every hour of the month.

MR. VIDAVER: Like demand response.

MR. MINICK: Yes, like demand response.

MR. VIDAVER: Mark, do you have any idea how the portfolio of resources that Edison has for RA fits neatly into these buckets, how much latitude?

MR. MINICK: Right now, it is not a restriction to us because we have not got that many peakers. I mean, we could build four peakers. They do have use limits on them. We bid them into the Resource Adequacy. We think right now they are not inhibiting us as far as our resource accounting, overall. As we get more and more peakers that might have use limits, we probably would run into some problems with our resource adequacy fund.

DR. JASKE: I wonder if there is another dimension of this, and that is, as the system -- and this will probably be a gradual process -- moves more toward reliance upon the various preferred resources that, by law, or the policy makers have pushed by decision, renewables, demand response, etc., will that place -- and they all have limitations compared to, you know, a power plant that is capable of running 8,760, other than maintenance down time -- is that going to place greater pressure on the remaining such class of power plants that will operate, sort of fill in all the holes left by all these other resources that have sort of a must take quality to them? And is the ISO sort of pursuing anything about that if it does perceive that as a problem?

MR. JOHNSON: The ISO, as you know, is very busy at trying to figure how to integrate for the future, you know, at the 20 percent renewable target, and the 33 percent, and we are in the process of looking at resource needs. But you are right, Mike, we are going to need -- there is going to be a different landscape going forward with a different resource mix than we have today. And it is going to be a different operating environment, much more challenging. You have heard us talk today about need for ramping capability, with the introduction of intermittent resources, and then we have heard, for example, Catalin this morning talking about inertia, where we would need a certain amount of mass as far as steel in the ground, power plants with mass, for example, in the LA Basin we would really continue to need that partly because of just the physical dynamics of the system, and then also the complimentary benefits it has for bringing in the imports, for allowing us to continue to bring in imports. But as far as -- you know, Mike, I think it is fair to say that that changed landscape will provide a bigger challenge for us to operate the system and it is probably going to change in some way the way we are using existing resources, and the way we will use resources in the future. I cannot say exactly how that dynamic may play out, but one thing that we have observed in certain periods of operating, you know, we have to make plants go up, come on, move up, go down. Some of the plant operators are not always thrilled with the way we need to operate them, given certain system conditions. So in the future, again, that is going to be a real challenge. It is going to be important among the work the ISO is doing, in cooperation with the other agencies, is to try to figure out what an optimal resource mix will be, or at least a viable resource mix will be as we move into the next decade.

MR. MINICK: We are doing some studies -- I mean, we are helping [inaudible] on this particular thing -- my biggest fear is two-fold, as mentioned by some of the people that build peakers -- I do not expect peakers to run at full load all the time when they are on. When we do more and more intermittents, they are going to be started more, and will be penalized for a half an hour early start, and you think you are going to have two a day, now you might have 10 a day, to make it more intermittents. That is the penalty that you are going to have to impose, which I think is -- I would not say silly -- but impossible to incorporate. Secondly, they are going to ramp up and down a lot, they are going to go from half load to full load to half load, and full load constantly, when you have all these intermittents, that -- if they are penalized like every hour of their run, their counter is fully on for Emission Offset Credit reasons, they are not going to be that fluid all the time and that is going to be a problem. Your original question was how many offsets. We do not know yet. There are so many different possible outcomes and scenarios about what resources get built and why. We need different peakers for solar than we need for wind, and we need different resources, depending upon location, depending on voltage control in the system, so we cannot give you a number except, I told you in my presentation, it could be 2,500 Megawatts or more. So we needed to at least get them when we started, and it could be 5,000, but we will not know the exact number until we do some more studies.

MR. SCIORTINO: Mike, can I offer kind of a mechanical -- it is not a huge solution -- but Larry alluded to it earlier in his presentation, that links the number of operating hours with the credits that you are getting. Now, Larry was very precise in saying that like people at GE will only guarantee a certain emission limit like, in our example, we were guaranteed three pounds PM-10 per hour of operation, so when we went through that exercise of reducing the number of hours of operation to try to fit under the 1304 rule, what we kind of came to realize was that, wow, that is GE's guarantee? That is what you have to go for your permit? That limits the number of hours you get permitted for? You always have the opportunity, and Larry alluded to this, six months down the road, in terms of after your commercial operation, you can ask the AQMD for another source test, and they will come out and they will measure what you are currently operating at. And historically, the LM 6000 is the only ones we have any experience with, historically they actually operate at 2 pounds per million, but GE does not want to guarantee that. So one of the small tweaks that you can do within the confines of the rules are you have a source test come out and if it comes out to be 2, then you get a new permit based on the 2 pounds, so you can actually increase your hours of operation by 33 percent. So in a sense, Larry, you touched on that. You said, well, if you buy them all at once, you have the option of either selling them back into the market because now you have got more than you need, or you can actually expand the number of hours that you can actually operate based on a revised permit. So it is kind of a small tweak in the system that allows you to increase some amount in terms of your hours.

DR. JASKE: But I guess I wonder, this is addressed to you, Mr. Nazemi, you know, were plants actually to operate in this mode where they are having very frequent starts, as Mr. Minick hypothesized, and ramping up and down, more so than just going up and staying at a constant level of output, you know, does that create worse air emissions, and what might you need to do to adapt your permitting process to deal with that kind of change in operating regime?

MR. NAZEMI: Actually, I do not know specifically what the emissions would be a different percent load for each pollutant to answer the question, whether it will be worse or not. But I think what I can offer, and I think that is what we have offered to project is, that that may operate at partial load and not full load is not to penalize it by the hour, but rather by the amount of fuel they burn. So when we ask a project proponent, give us your worst monthly usage, we ask them what is the maximum amount of fuel that you use in one month, we will divide that by 30, and that becomes their daily liability for offsets. The question of, well then, what if we gave you an emission factor that is guaranteed by a manufacturer, and then later on we did a source test and it showed something lower, and then we want to change our permit, is somewhat problematic, in particular for pollutants that we cannot continuously monitor, because you can always count on a piece of equipment to do its best when you are doing a source test, and then a month later, or a week later, you do not know if it is operating at that level or not. But, for example, on our Reclaim Program, we do that with NO_x because everybody has to have a continuous monitor, and you know exactly in what day, in what month, and in what quarter how much NO_x they emitted, and they are only held liable for that amount of NO_x emissions. So I think it depends on the type of project and the partial versus full load can be addressed, so I think that is something that we do take into consideration, but to do a snapshot and say, "Well, now that we have found the perfect fit, let's change our permits to something different" is somewhat problematic, and I think we can only deal with those types of requests if it is a continuous monitoring scenario.

DR. JASKE: A question from -- that came out of perhaps Mr. Kostrzewa's presentation this morning, or earlier this afternoon, would a limit on -- would an alternative permitting process that focuses more on expected hours of operation and less on the potential with some kind of mechanism to make the District whole, should expected hours be exceeded because of some system operating conditions, Mr. Nazemi, can you foresee the District's rules shifting more towards that basis if there really was a legitimate basis for that sort of truing up so that we could minimize the gap between the expected level of emissions and emissions based on potential?

MR. NAZEMI: As long as it is consistent with federal and state law, yes.

DR. JASKE: And can you imagine the state and federal processes adapting themselves to that change in any realistic period of time?

MR. NAZEMI: I think that is pure speculation. I do not know if my answer is going to be worth much. But I think it is important to keep in mind that there is -- whenever you talk about federal law, you are having national implications, not just what is going on in Southern California, so that makes it that much more difficult. And, again, under state law, there are some hurdles that you need to jump over and you are not certain until you jump over the hurdle whether you are going to knock it down or not, and that is not the decision you make, it is someone else's decision, so it is kind of hard to really say, yeah, if we made this more reasonable, and everybody agrees this is more reasonable, but does that adhere to the law or not? That is the difficult part. I am sorry I cannot give you a better answer than that.

DR. JASKE: Does the developer group -- do you have any reactions to the question or his response?

MR. KOSTRZEWA: I agree that it would take an effort to get those rule changes made, but I would encourage the District to continue to think out of the box, as they have been. You know, if we could go from next month, to annual, to maybe a two or three year rolling, where every single pound was offset, but over a wider averaging period, that would greatly diminish the problem. But, as Mohsen points out, that would take the will of the state to implement that.

MR. CARROLL: I mean, I think that there are certain constraints that are obviously imposed by federal law, and unless we want to go [inaudible], as I said earlier, everything should be on the table, including that. But if we assume for the moment that we are going to go out and try to propose solutions that fit within the constraints of existing federal law, I think there is still some latitude within those constraints to build additional flexibility into this permitting program. I think it is absolutely correct that state law needs to be analyzed, but I do not think that is a reason to move forward with these. I mean, as you can tell from these discussion, there are no easy solutions, if there were, we would have implemented them. So with respect to every single one of these solutions, we would say, well, no, there is that problem, or no, there is this problem, we will not get anything done if we allow that to stop us. So I think we move forward, you know, the District established the Resource Review Working Group, it met on a few occasions, I think there was some very good progress made on a number of the proposals that have been discussed today. That working group has not met for quite some time. I know that everybody has been very focused on legislative efforts, but I think it would be very helpful to get that group reconstituted, and to pursue these issues. And some of them may require an analysis under SB 288, if that is the case, then let's get on with the analysis. But I think that there is definitely room to maneuver here. That does not mean it is easy, but just because it is not easy does not mean that it should not be pursued.

DR. JASKE: So, Mr. Nazemi, earlier this afternoon I asked you what you thought the right forum was to pursue these issues, and your response focused on the sort of electricity need side of things. Mr. Carroll is obviously suggesting that the emissions side be examined in parallel, so is the District's NSR sort of working group process something that can take on -- if it has not already -- the emissions side of things, while perhaps the energy agencies try tackling the electricity system needs side of things?

MR. NAZEMI: I think our NSR working group is a good example that the District is willing and interested to look at all available options, that we have not made a decision that, no, we are not going to do anything. What I think is important to keep in mind is that that process is going to be time consuming, and if you are -- that is why maybe the reason that the energy analysis is also important is that, depending on what the timeframe is for the needed electricity, that process may or may not work. I mean, if you are saying that you need these -- as was indicated earlier -- steel in the ground in 2010 and 2011, so that you can supply the power, then your permitting needs to happen like yesterday, and so this process is not going to help. But if you are looking into fixing the problem, not fixing, but maybe at least making it less burdensome, yeah, there is definitely room to work in. And as you heard Mr. Carroll, our agency's position is not that we are not willing to work on this, but I think we all have to realize we have come to a very unique and unusual time in our 40 plus years of experience in Air Quality, which is that we have been prohibited from permitting over 1,200 permits, that are worth a lot of investment, employment, and some of them are actual beneficial to the environment. And so we think it is more important to us than to get involved in a very long process of rulemaking and litigation on changing NSR rules when we have something more urgent on our hands, so we are not setting it aside, we are just doing what we think is necessary right now.

MR. CARROLL: But if we do not fix the NSR rules, the crisis that we are in the middle of right now is going to recur, and so you cannot put off fundamental issues that are precipitating the crisis in the hope to avoid it in the future. So, again, we have all had a lot on our plates, I am not diminishing that in any respect, but I think we need to now turn to the underlying problems that precipitated this crisis and try to address it. And one of the issues -- and I agree they are not going to be in place tomorrow, but one of the things that is going to get put on the table that, frankly, is one of the very few proposals that everybody, including the environmental community supported, is pushing off the deadline for having offsets in place until commencement of operation versus commencement of construction. If we put that fix in place, we have bought ourselves about two years to implement some of these solutions. So there is a package here that works, and I get a little frustrated with all this, "Oh, gee, it is too hard, gee, it takes too long, and you need to go first, and we'll wait to see what you come up with before we get started." I mean, everybody needs to come together and start working on these solutions, whether they are easy or quick to implement or not, because the problem is not going to get solved otherwise, and it is not going to go away with time.

DR. JASKE: Other sort of final comments?

COMMISSIONER BYRON: Gentlemen, I think we have -- I feel like we have underutilized all of you, that there is discussion and it could continue, more than we can address. I would just like to take a moment, though, and turn to our representative from LADWP who we did not hear from during this panel, and ask if there was anything in particular you wanted to add or say?

MR. MOORE: Yes, the AMQD had a solution to this problem when they promulgated Rule 1309.1, and it would have provided credits for electric generating facilities, and it was challenged on the basis that the CEQA analysis was inadequate. The idea was that the AQMD would have to look at all of the emissions impacts from the credits that would be dispersed from the credit bank in the coming years, even though each of the projects would themselves have to go through CEQA. One solution might be to amend the CEQA regulation to exempt the AQMD and such agencies from needing to go through CEQA when promulgating regulations relative to credit banks. The public health and safety would be protected, as I said, because each of the individual power projects would itself have to go through the full CEQA process. This would seem to be an easier lift than turning the problem over to the state, to a state agency. So I would ask Mohsen if this is something that the AQMD has considered, attempting to get the state CEQA regulation amended?

MR. NAZEMI: I feel like that is what we have been trying to do for the last year, and this is where we are. SB 696 initiated that process and it did not get anywhere.

COMMISSIONER BYRON: Gentlemen, I appreciate it, but I think in the interest of time, we are going to go ahead and move to public comment. You are welcome to stay at the table because it might be an opportunity for a little more discussion as we get public comment, but I understand we are also getting late. Part of the problem is we started at 10:00 in order to make it easier for folks to travel here from the South. I hope you will stay and support the economy and have a good dinner here in Sacramento. But let's go ahead and move to public comments. And, again, you are welcome to leave, but you are welcome to stay because maybe there is some opportunity for some interaction. I do have a couple of blue cards, Ms. Korosec. Shall I go ahead and start with those?

MS. KOROSEC: Yes.

COMMISSIONER BYRON: We have got some patient folks that have been sitting here for the day absorbing all this information, and I will just take them in the order received. Jesse Marquez, Executive Director of Coalition for a Safe Environment. Mr. Marquez.

MR. MARQUEZ: I would like to thank you for this opportunity to speak with you in public comment, but I also have a grave concern. Our nonprofit organization is an environmental justice organization headquartered in Wilmington. We have members in over 25 cities in Southern California, which are mostly parents, residents, students, elderly, as well as a few small businesses that support the work that we do. And our concern is that you have held a hearing today, or a workshop, whereby there is not one public interest ratepayer interest organization as a participant. We spent here seven hours approximately where you had the opportunity to hear the experts of all fields in the energy field, as well as governing agencies, but then where is the public's interest and the ratepayers' interest in participating? It is not there. So my first request would be of you, if you could hold another public meeting and invite public interests and ratepayer organizations to be able to provide comment to you, so you can see and hear an alternative perspective on what is being discussed today. Some thing that have been discussed have been regarding and in reference to the Clean Air Act, as well as CEQA. The majority of the U.S. public supported the Clean Air Act, and we believe in it, and it has worked very successful for us. California residents supported and voted for the CEQA law. It has been very effective and we support it 100 percent. There is no environmental justice organization in California or in the United States that wants to amend the Clean Air Act or the CEQA Act to make anything convenient for a polluter to do his business. And we do not want that to be one of the criteria. I am one of the litigants in the lawsuit -- we are being represented by NRDC. The South

Coast was found guilty of violating the law. In that sense, in the public's eye, it appears that they colluded with the power generating industry to get their demands met, and that is how it is viewed by the public. It was secretly done. Ron Wright's Bill was gutted in a minute, the last minute, there was no public participation in that. There was not an opportunity for all the different residents and organizations in the state of California to hold public meetings and testify and come to the Assembly Committees and Subcommittees, everything was done as a last minute thing. And that is not fair to the public to be able to do that. I am not an expert myself in energy generation, but I can share with you some of the experiences and some of the knowledge that I do have. I am also a member of RACE, Ratepayers for Affordable and Clean Energy. We are also a member of CARE, Californians for Affordable and Renewable Energy, and we are also a member of the Sierra Club Harbor Vision Task Force. And so, as a member of those, I also speak on our behalf with those references. Since we represent residents and the public, we look at the common sense model. We may not have a lot of computer models of other types, but some things are very common sense to us, and we have to look at very complicated issues. But we do have things that we do read in newspapers. I do attend many meetings. I do read quite a few documents, so I can have a grasp of certain things. And one of the big fears and concerns we have right now is a word that is being used very freely, as pointed out by the gentleman over here, we are not in an energy crisis today. The last thing I read about our energy shows that we have about a 20 percent cushion. So there is a fear being generated that we have dire consequences for tomorrow or next year, which is not true, so there is no reason to ramrod things through when there does not have to be.

Now, do we see a necessity for planning for energy? Yes. We support planning 100 percent. But creating a fear that there is a crisis is not true, or try to hide it under the guise that we are in an economic crisis now and we need more jobs, we need to keep it in its proper perspective, so we do not see it as a crisis. You are going through a proper planning process and we need to have the public participate in that planning process. Do we see energy needs for the future? Yes, there is population growth, there is business growth, but then there is also a smart planning process. As an example, I participate on the Port of Los Angeles and the Port of Long Beach, and the refinery issues down there. Our participation at the Port and Harbor Commission meetings, just like your Commission meetings right here, is that we asked them years ago that why can't the ports have solar energy there when you have thousands of acres of open space. And, no, they do not have to be 10 feet tall, they can be put on poles and canopies, you know, 40-50 foot tall, or even higher so they do not interfere with the normal container stacking. But after six years of asking for that, they listened. Last year, the Port and Harbor Commissioners voted to go forward with creating 10 Megawatts of solar power there at the Port of LA. They just approved a month or two ago the first contract for the first Megawatt of solar power. So in some cases, we are not talking about huge 500-800 Megawatt facilities, but we are realistic, too, we do see industries that are local and they do not need to have those big facilities, but they are looking at a smart approach, and we support 10 Megawatts of solar energy because they also did a little bit of a study to see what would their energies be over the next five to 10 years, and it came out to be about 10 Megawatts. So that falls on that term that you use -- distributed generation? Well, we consider this distributed generation. But we see, then, that they can also in the future go to 20 Megawatts, 30 Megawatts, and now we are working with the Port of Long Beach, and they have already informed us that they are looking at the potential for solar energy there, as well. Now, is there a wind energy application at the ports? Absolutely. In the evenings, everyone that lives by the coast know about if a wind has come in, so we have asked both ports to look at wind energy. Now, some people are going to say, "Oh, yeah, well, then you are going to have to worry about the windmills killing the endangered species, birds," well, we have also looked into that, and we also realize that there are those vertical turbine windmills that do not kill birds -- we have seen them and there are different styles, I can actually show you a notebook I have of about 50 different applications of vertical wind turbines that would not hurt birds. But we see that as an avenue to go, as well, again, being distributed. We have seen nightmares occur. Last year, CPUC approved SEE to enter into a contract with NRG to repower a power plant that was closed down and built in 1929 at the Port of Long Beach. I opposed it. I appealed it before the Board of our Commissioners of Long Beach, I appealed it before the City Council, I went before them. I said, "Here you are approving this power plant. It is going to have a certain amount of air pollution coming out of it. What are all the terms of this deal?" And when I looked at the terms of the deal myself in order to respond to our members in Long Beach and other communities, it was a $300 million contract for 10 years, $30 million a year for them to be on standby for 150 hours. So I asked the Port of Long Beach, and I asked the City of Long Beach, all 15 Council members whether the City of Long Beach could negotiate with that in their benefit. Is there a clause in that contract that the City of Long Beach or the Port will not be blacked out or browned out? The answer was no. So here is a nice signed deal and today, right now, there could be a black-out in Long Beach, and they have no benefit of that new power plant now coming online. I even asked NRG, "Could you invest some of that money in some solar energy, on public schools, municipal buildings, as a good gesture?" They refused. In fact, they did promise me that same, "Oh, we'll create a fund afterwards, maybe for some public education on energy conservation, etc." They never came through with it. So we do not see that as a good deal. Then we hear about BACT, Best Available Control Technology. Well, we have done research on Best Available Control Technology and we have some problems with it because AQMD can approve a technology as a BACT, and it could be a 95 percent effective one, it could be a 90, 80, 70, 60, 50 percent efficiency. All of them are called BACT. So, what I have to say about BACT now, it is not acceptable to us, the public, that have learned about BACT. What we want is MACT, the Maximum Achievable Control Technology, which means the number one best. Now, if a couple of competitors happen to be within 5 percent of each other, I have no problems with that, but if there is a difference of 10, 20, 30, 40, 50 percent between the technologies, and one of these power plants is choosing one of the least costs, which means least efficient technologies, then we have a problem with that because BACT is no longer acceptable to us, because when we do a little bit more research and find out there are companies that do have technologies out there that we feel are better, none of these companies are using them, and none of them are in the applications that you have approved at this point in time. And one of those happens to be the EMX Technology, two of the principals happen to be here, EmeraChem, and, well, we have an opportunity to read some of their documentation and to take a look at it, and we feel that they are one of the better, if not one of the top three best, but no one is incorporating their technologies into their facilities. So I think, before you approve a permit, then there should be one more public request that, where the public can come in and say, "Wait a minute, we looked at the equipment, they are not using the Best Available Control Technology, no permit should be issued until we can confirm what is the Best Available Control Technology," and that is not being done. I have now submitted public comments on 17 Title 5 permits for the oil refineries and petroleum industry, and we asked AQMD, we wanted to know the efficiency factors of the equipment because you are putting it into the permit. We are still waiting now to hear and read any of that information, none of it has been provided. So we still have no clue how efficient the equipment is at these facilities. So I think there needs to be some type of score card, rating system for equipment, so we have some idea how good is the system, how good is the technology. And what are other alternatives? I also found out about another piece of equipment that would be great for you to know --

COMMISSIONER BYRON: Mr. Marquez, I have other commenters. How much more time do you think you will need?

MR. MARQUEZ: Five more minutes.

COMMISSIONER BYRON: How about three?

MR. MARQUEZ: Okay. Oh, this is a piece of technology which is a hydroelectric. What it is, it is an inline system that goes into pipes, that could be a water line, oil pipe, any type of effluent line, and what it is, it is like a little generator, just like you have in a big dam.

COMMISSIONER BYRON: Mr. Marquez, we are well aware of the technology.

MR. MARQUEZ: Okay, but again, where is that figured in where it can be used and applied. It is not. I will also mention about mitigation funds. We support having mitigation funds to offset impacts in the community, but we also have terrible results with some of that. AQMD won a BP lawsuit, $30 million, $3 million a year for the next 10 years. BP is located in Carson, Wilmington is right across the street, West Long Beach is just downwind. So when the first $3 million came up for mitigation, we did not see a dime of it, however, the Chairman of the Board issued $1 million to three of its favorite charities, of which he was on the board of directors of, that we discovered later. What happened the second year? To cover up that, the 15 Board members divided up the $3 million and each one got $200,000 a piece. So what mitigation is being proposed, we the public want to be part of that process, to what are going to be the rules and regulations, and how it is going to be spent, and who gets to participate in getting approved to use that money because we are not benefitting from it. I can tell you right now, Wilmington, the public got less than $50,000 worth of services out of the last six -- well, about $9 million that has been spent right now. And I will be submitting some public comment. And I thank you for this time.

COMMISSIONER BYRON: Thank you. Adrian Martinez, Natural Resources Defense Counsel. Mr. Martinez, thank you for being here. I am sorry that other members of the organization could not be present today.

MR. MARTINEZ: That is fine. Good evening. I think what I am taking away is NRDC and probably other groups will be submitting some rather extensive comments on this process, and I think that will be useful --

COMMISSIONER BYRON: On the process? Or on the content?

MR. MARTINEZ: On the content, oh, we might mention the process, but we will focus on the content. We have heard several novel interpretations of the law that we might weigh in on; also, several proposals that, in fact, provided me grave concern, and I am confident once I take it back to my colleagues at NRDC, it will cause concern for them, including discussions of CEQA exemptions, amending the Clean Air Act, both the state and federal version. I think these types of discussions need more vetting and I think we will go to our colleagues who are concerned with the integrity of the state and federal Clean Air Act, and the California Environmental Quality Act, and discuss what happened today and what transpired.

COMMISSIONER BYRON: What did happen today? Maybe I missed it. Did we suspend CEQA here today?

MR. MARTINEZ: No, just several proposals were put on the table, and I think my assumption is the Energy Commission will do its due diligence in examining all those proposals, and I just want to make sure what was primarily tilted towards one side of the debate, the discussion today was tilted towards one side of the debate, and I think it is informative if you go to the other side of the debate. It was very important to have this discussion, I learned a lot, and actually heard a lot of important views from several project proponents, the Air District, and several other interests. So we will be providing these comments and I think they will provide some clarity on our position, especially provide some perspective on the litigation, also the health concerns with several new power plants, and also put some perspective on the emissions credits as a whole. As was mentioned briefly, the power plants are one small portion of facilities that actually need credits. In fact, there are many other facilities needing credits, including hospitals and other facilities, and, in fact, the power plants used a lot of credits and that is why we are here today, that is why you have such a robust participation in this discussion. So we will be following up by the October 6th deadline with some comments to the Commission.

COMMISSIONER BYRON: Good. Let me ask you a question or two.

MR. MARTINEZ: Yes.

COMMISSIONER BYRON: You are also a plaintiff, as I recall, in the litigation. Is that correct?

MR. MARTINEZ: Yes, NRDC is a plaintiff.

COMMISSIONER BYRON: You know, I was struck by the comments that you provide, and we welcome them, and we want them. No decisions were made here today and there is an implication, I think, in some of the concern you have expressed. I really took from the presentations and the discussion -- everything seemed to be, in my mind, geared towards solutions and, yes, the table was open for discussion, all things considered. And, of course, what really was not described today is, well, what are we trying to provide -- I should not say it was not described -- maybe we should have started with what are we trying to solve here.

MR. MARTINEZ: Yes.

COMMISSIONER BYRON: And it would seem to me, and I am not an expert with regard to the litigation and its current status, that that is really what we are trying to address, is the pending litigation and the potential outcome from that. Can you speak to the issue, or will you be able to speak to the issue in your comments, what is the goal of your litigation besides proving, indeed, that somebody did something wrong? What are we trying to accomplish with the long run goal with the litigation?

MR. MARTINEZ: Yeah, we will address that in our comments. I mean, I think the goal of the litigation, the national litigation, has been skewed to one perspective today. I think there were two rules on the table that the Air District adopted, one was 1309.1, which allowed power plants access to the Priority Reserve, the second was an emission credit generating rule 1315. We initially sued because there was not a CEQA analysis that was adequate. We have had several judges agree with us --

COMMISSIONER BYRON: I am sure you are right, I am sure the judges agree, and I am sure you right. I am trying to understand, what is the goal? What are we trying to accomplish with the litigation?

MR. MARTINEZ: Well, as you are well aware, with the CEQA remedy, it is an environmental analysis. There has not been an environmental analysis of the impact of Rule 1315 and 1309.1. It is our understanding that the Air District is not pursuing Rule 1309.1, the amendments to allow power plants, and solely pursuing Rule 1350, at least I do not want to put words in their mouth, they might -- I do not know the state of what they are doing. But we continue to believe that there still needs to be an environmental review of Rule 1315 and its impacts on the Basin. There has not been much discussion that the Los Angeles reason has some of the dirtiest air in the nation. We continue to fail to meet attainment. We are actually likelihood on this attainment deadline comes due in 2010. There was a promise made to residents that we would need attainment, and yet we are not going to meet that goal. And so NRDC, other groups, have a continued commitment to push the Air District to meet attainment. Now, concurrently, there is another goal, is to make sure that power plants, especially fossil fuel powered power plants in the Basin are needed, and I think we continuously requested a needs assessment. I think that process is starting to progress. Several agencies need to discuss -- I actually disagree that there should be just wholesale building of power plants in the region, I am not convinced that is necessary. Now, the analysis is done and that is the conclusion, then I will look at that analysis, the numbers, and the information. And make an independent conclusion from that. It is not -- from what was presented today, I am not convinced that the number of power plants slated for the region are needed. And, in fact, today we saw one power plant get removed -- it removed its application. So I think there are issues and there are power plants that may not need to be built, and that is what we are interested in. We are interested in that analysis and that process. There needs to be a public process which, as you described, having the information so people can tear into it and really understand why we are building these power plants, why we are building them in certain communities, and other considerations like that.

COMMISSIONER BYRON: Well, thank you very much for being here. I welcome your written comments and please remember, this is not a court of law. We are interested in solution-based comments, so if you have recommendations that you can make along those lines, they are more than welcome.

MR. MARTINEZ: And as are we, we are also interested in solutions. Mr. Carroll pointed out some areas where everyone kind of agrees, so we will point to those solutions in our comments.

COMMISSIONER BYRON: Thank you, Mr. Martinez. Okay, I could not read it at first, I apologize, Gary Rubenstein, Sierra Research. Thank you for your patience, Mr. Rubenstein.

MR. RUBENSTEIN: Thank you, Commissioner Byron. I know it is late, I will keep my comments brief. One of the speakers very early this morning, I think it was still this morning, made a comment about how an economist might assume a can opener as a solution to opening can of beans on a desert island. There is one assumption that has been made in virtually every presentation we have heard today, and that is the assumption that we actually know what the particulate emissions are from gas-fired power plants. What we actually know is what vendors guarantee, and what we know is what project developers assume is a level of risk behind that guarantee. This Commission co-sponsored research as far back as 2001 demonstrating that, if you used more modern methods to measure particulate emissions from gas-fired turbines, the actual emission rates are roughly 10 times lower than the numbers that you typically see in a licensing case. That was not a fluke. And there has been continuing work that has gone on over the last eight years. Most recently, there were a set of tests that were done here in Sacramento with the Cosumnes Power Plant in a report that was just released, demonstrating that most of the particulate emissions that we think we are measuring are actually indistinguishable from the background that we were trying to measure it from. Basically we are stuck trying to measure zero. And a couple of speakers have alluded to how they have taken a risk on as project developers to try to license emissions rates that are maybe 20 percent, maybe 30 percent lower than the render guarantee, but the underlying fundamental problem has to do with the test method. There are a couple of new generation test methods that have been developed. And before someone suggests that they have to be EPA approved, they are. Those methods demonstrate substantially lower emissions and, if you think about all the numbers we have talked about today, if you divide the particular emissions problem we are trying to deal with in power plants by 10, it fundamentally changes the calculus. Solutions that we think are insurmountable suddenly become potentially possible. The magnitude of the problem is just much better, and I would simply strongly suggest that you include in your analysis, review those test methods, ask the relevant air agencies what they think of the new test methods because, to the extent that we can develop some support for the use of these methods and licensing procedure, and in compliance procedures, I think it becomes a much more manageable problem. Thank you.

COMMISSIONER BYRON: Thank you. And you bring up in a very short period of time something that addresses this issue, potentially, and in a substantial way. This is PIER research, I think, that you were talking about, PIER research projects -- Public Interest Energy Research funded project.

MR. RUBENSTEIN: The 2001 analysis was; the 2008-2009 study was privately funded.

COMMISSIONER BYRON: Mr. Nazemi, do you want to address this in any way, briefly, if you do not mind?

MR. NAZEMI: Really briefly, I think Mr. Rubenstein has been communicating with our agency in quite detail about these new test methods, and we have had our source testing experts review the methods and provide comments to the group that Mr. Rubenstein was working with, and we are working towards improving the test methods, but I think there were some specific concerns that we had with the test method, and I do not think it is the place to get into it here.

COMMISSIONER BYRON: Okay, but obviously you are aware of this and it is under consideration. I appreciate your comment, Mr. Rubenstein. If you can also figure out who the lawyers can still get paid, somehow, so they can feed their families, then maybe we will have a solution here.

MR. RUBENSTEIN: Thank you.

COMMISSIONER BYRON: Thank you. The last card I have here at the Dais is Jeff Valmus, General Manager of -- and I will let you identify it so I do not misstate it.

MR. VALMUS: Good evening. My name is Jeff Valmus and I am with EmeraChem Power. Our company is, since 1992, has been providing air pollution control equipment for stationary sources. We provide traditional technologies like SCR, and we also provide multi-pollutant, ultra-clean technology EMX. I want to approach this from a little bit different angle tonight and I have heard a lot of comments and discussion and concerns, obviously, over the amount of credits, the scarcity of them, whether that be PM or NO_x credits, or the cost of those credits. And certainly those are all issues here. But what I have not heard is any solutions regarding it from a technological standpoint, and I certainly heard it from an alleged slate of viewpoints, policy viewpoints, and everything else. And I believe, as a member of the NSR Working Committee, that we need to look at all of those things, and they are all important, and there are many things we can do within that committee that can help provide solutions. I want to talk about a little bit of advanced technology here. The EMX, the lean NO_x trap technology, performs better than current BACT for all criteria pollutants. It is capable of generating these ERCs that are so direly needed for PM, NO_x , VOCs, and for sulfur, because of its high availability to remove efficiencies. The guarantee level for PM from our system reduction is 50 percent. That means every single stationary source that we are trying to permit here today, if it utilized our technology, would require 50 percent less credits in order to be put in place. At the same time, it will control NO_x levels of below 1 ppm. It will also create sulfur reductions anywhere between 90 and 95 percent, and it will control CO at 99 percent, and it also has no ammonia slip. This is a game changer. It has the ability and what is very similar looking to an SCR type system to provide credits and PM and SO_x, all that we need. It also provides a great deal of operational flexibility due to the ability to remove these emissions credits. We have heard a lot today about power plant developers having to put a lot of capacity in because they are not able to run a lot of hours there. This provides the ability to run a lot of hours. You now, all these simple cycle plants that are being considered here, you know, they have a lot of emissions when you can start from start-ups, to shutdown, transients, and when they operate at low loads, these emission levels go through the roof. So EMX has the capability like NCR to be able to control those emissions during those times, so it also helps reduce it, and as such, you are going to be able to run one more hour in the long run. It is also commercially available right now. We have been operating for 10 years on ten plants, and with over 420,000 hours of operation at 99 percent availability. It is a robust system, it is available now to help with the solution.

COMMISSIONER BYRON: Do you have any units in California?

MR. VALMUS: Yes, we have a unit up -- we have several units in California. The closest is the City of Redding, it is a 50 Megawatt facility, and it has been operating since 2002 at levels between .5 and 1.0 ppm NO_x levels. At the same time, we just recently in 2007, summer, performed PM testing at that facility where we averaged over 50 percent PM reduction through our systems. So we do have the results of that. It can help relieve a lot of the stress in the burden we are seeing here. It can also help with the ability to retire the OTC plants. It has the ability to generate ERC credits, not only lower the demand of new facilities, but it also has the ability to go retrofit and create an ERC. So I think it is an important technology that needs to be more considered in these kind of circumstances where we are looking to try to build power here in the South Coast, and beyond, and we have been working with the environmental groups, we have been working with the business groups, and we have been working with the South Coast, as well as the other agencies in the State of California. And we are trying to make them aware that this technology exists, it has a lot of experience, and it is capable of providing some silver bullet solutions up there.

COMMISSIONER BYRON: All right, thank you. That is the extent of the comment cards I have, however, I always make sure that we do not leave anybody out. Any other potential commenters this evening? If not, I would like to thank you all very much for your participation. It has been a long day, we covered a lot of material, and I really do appreciate your input. It has been extremely valuable in our formulating recommendations in our Integrated Energy Policy Report, and I think that is it. We will be adjourned.

(Whereupon, at 6:00 p.m., the workshop was adjourned.)

--o0o--

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said meeting, nor in any way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this _____ day of October, 2009.

PETER PETTY